PHMSA 000109256

BP EXPLORATION (ALASKA), INC.

OIL DISCHARGE PREVENTION AND CONTINGENCY PLAN

NORTHSTAR
NORTH SLOPE, ALASKA

VOLUME 1 OF 2, RESPONSE ACTION PLAN

MARCH 2012

BP EXPLORATION (ALASKA), INC.

NORTHSTAR OIL DISCHARGE PREVENTION AND CONTINGENCY PLAN

Volume 1 of 2, Response Action Plan

MARCH 2012

PHMSA 000109260

BP EXPLORATION (ALASKA), INC.

NORTHSTAR
OIL DISCHARGE PREVENTION AND CONTINGENCY PLAN

MANAGEMENT APPROVAL AND RESOURCE COMMITMENT STATEMENT

This plan is consistent with the requirements of the National Contingency Plan and the Alaska Federal/State Preparedness Plan for Response to Oil and Hazardous Substance Discharges / Releases (Area Contingency Plan). It is approved for implementation as herein described. Manpower, equipment and materials will be provided as required in accordance with this plan.

BPXA's approach to oil spill response will be based on the following priorities:

1. Safety of personnel
2. Protection of the environment
3. Protection of facilities

Terry Welch
VP Operations

Terry Welch

Date

9/26/14

BP EXPLORATION (ALASKA), INC.

P.O. Box 196612
Anchorage, Alaska 99519

900 East Benson Boulevard
Anchorage, Alaska 99508

(907) 564-5111 - telephone

bp

PHMSA 000109261

THIS PAGE INTENTIONALLY LEFT BLANK

PHMSA 000109262

RECORD OF REVISIONS FOR VOLUME 1

REVISION NUMBER	REVISION DATE	SUMMARY OF REVISION CHANGE
1	Oct. 2012	Plan updates included: • The words "spill" and "release" were replaced with the word "discharge(s)" in footnotes 1, 2 and 3 of Table 1-4 (Agency Reporting Requirements for Oil Spills), and • Facility Response Plan (FRP) for U.S. Coast Guard was renewed October 2, 2012; FRP now expires October 2, 2017.
2	January 2013	Updates to Figure 1-2 (Northstar Incident Management Team), Table 1-2 (GPB Incident Management Team), and Table 1-3 (BPXA Contact List).
3	March 2013	Plan updates included: • Section 1.6.2, Recovery Procedures, was removed; the information was obsolete. • In Scenario 2, the oil recovery rate for the Crucial 13/30 skimmers was adjusted and Table 1-14 and Table 1-15 were modified accordingly. Typographical errors were corrected in the equipment and staffing tables for Task Force 5.
4	August 2013	Edits and updates to BPXA Contact List (Table 1-2) and minor edits to other various sections in Part 1; updates to Section 3.12, Bibliography; and replaced the expired Bureau of Safety and Environmental Enforcement Facility Response Plan with the version approved on June 26, 2013.
5	January 2014	Edits and updates to: Plan Renewal section in the Introduction; Figure 1-2: Northstar Incident Management Team; Table 1-2: GPB Incident Management Team; Table 1-3: BPXA Contact List; Table 1-4: Agency Reporting Requirements for Oil Spills; Section 3.12: Bibliography; and, the BSEE Oil Spill Response Plan in the OPA 90 Appendix.
6	April 2014	Edits and updates to: Figure 1-2: Northstar Incident Management Team; Table 1-2: GPB Incident Management Team; and, Table 1-3: BPXA Contact List.
7	August 2014	Edits and updates to: Figure 1-2: Northstar Incident Management Team; Table 1-2: GPB Incident Management Team; and, Table 1-3: BPXA Contact List.
8	September 2014	Edits and updates to: Management Approval and Resource Commitment Statement; Figure 1-2: Northstar Incident Management Team; and, Table 1-3: BPXA Contact List.

PHMSA 000109263

THIS PAGE INTENTIONALLY LEFT BLANK

PHMSA 000109264

TABLE OF CONTENTS FOR VOLUME 1

PHMSA 000109266

LIST OF FIGURES FOR VOLUME 1

LIST OF TABLES FOR VOLUME 1

LIST OF ACRONYMS FOR VOLUME 1

AAC	Alaska Administrative Code
ACP	Area Contingency Plan
ACS	Alaska Clean Seas
ADEC	Alaska Department of Environmental Conservation
ADFG	Alaska Department of Fish and Game
ADNR	Alaska Department of Natural Resources
ADW	Alaska Drilling and Wells
AOGCC	Alaska Oil and Gas Conservation Commission
API	American Petroleum Institute
ARRT	Alaska Regional Response Team
ATV	all terrain vehicles
BAT	best available technology
bbl	barrels (42 gallons)
bbl/LF	barrels per linear foot
bbl/min	barrels per minute
BOPE	Blow out prevention equipment
BOP	blowout preventer
bopd	barrels of oil per day
boph	barrels of oil per hour
bpd	barrels per day
BPXA	BP Exploration (Alaska), Inc.
BSEE	Bureau of Safety and Environmental Enforcement
°C	degrees Celsius
CFR	Code of Federal Regulation
cm/s	centimeters per second
DOT	U.S. Department of Transportation
EPA	Environmental Protection Agency
°F	degrees Fahrenheit
FLIR	Forward Looking Infrared
FOSC	federal on-scene coordinator
GHz	gigahertz
GOR	gas-to-oil ratio
GPB	Greater Prudhoe Bay Unit
gpm	gallons per minute
HAZWOPER	Hazardous Waste Operations and Emergency Response
IBRRC	International Bird Rescue Research Center
IC	Incident Commander
ICS	Incident Command System
IMT	Incident Management Team

LEL	Lower Explosive Limit
LPC	Lisburne Production Center
MAD	Mutual Aid Drill
mPas	milliPascal seconds
NCP	National Contingency Plan
NIMS	National Incident Management System
NIST	National Institute of Standards and Technology
NPREP	National Preparedness for Response Exercise Program
NRC	National Response Center
NSSRT	North Slope Spill Response Team
ODPCP	Oil Discharge Prevention and Contingency Plan
OPA 90	Oil Pollution Act of 1990
OSHA	Occupational Safety and Health Administration
OSRO	Oil Spill Removal Organization
PPE	personal protective equipment
RPS	response planning standard
SOSC	state on-scene coordinator
SPCO	State Pipeline Coordinator's Office
SRT	Spill Response Team
UHF	Ultra High Frequency
USCG	U.S. Coast Guard
USFWS	U.S. Fish and Wildlife Service
VHF	Very High Frequency

INTRODUCTION

This Oil Discharge Prevention and Contingency Plan (ODPCP) covers the Northstar Unit, which is located 12 miles northwest of Prudhoe Bay, Alaska and 6 miles north of the Alaska coast (Figure I-1). The Northstar facilities are comprised of a production Island in the Beaufort Sea and a crude oil transmission pipeline extending from the production island to Pump Station 1. BP Exploration (Alaska), Inc. (BPXA) operates the Northstar production facilities.

The ODPCP addresses oil spill prevention and response requirements promulgated by the State of Alaska in Title 18, Chapter 75 of the Alaska Administrative Code (AAC). It is comprised of five parts consistent with 18 AAC 75.425(d)(2). As allowed under 18 AAC 75.425(e)(2), the ODPCP is represented by two volumes: Volume 1, Response Action Plan, and Volume 2, Prevention Plan. The Response Action Plan (Volume 1) is contained herein.

The ODPCP also addresses federal oil spill planning regulations of the U.S. Department of the Interior, Bureau of Safety and Environmental Enforcement (BSEE), U.S. Coast Guard (USCG), and U.S. Department of Transportation (DOT).

The Response Action Plan, with the resources and equipment listed herein, is a planning document that demonstrates the potential response capability available to respond to an oil spill from tanks, pipelines, wells and other equipment covered by this plan. It is not a guarantee of what will occur, or the resource deployment sequencing that will be used in an actual spill event. Nothing in this plan is intended to limit the discretion of persons in charge of an actual spill response to take the actions deemed necessary to maximize the effectiveness of the response, consistent with safety considerations. Response operations in a spill event will be tailored to meet actual circumstances.

This plan incorporates by reference some information provided in the Alaska Clean Seas (ACS) *Technical Manual*.

PLAN DISTRIBUTION

The Response Action Plan is maintained on the BPXA intranet website, accessible by BPXA employees and contractors. Hard copies of the plan or electronic copies on CD are distributed to regulatory agencies and emergency operations centers. Additional copies are in the Anchorage Crisis Center, the Safety & Operational Risk (S&OR) Department, and at ACS. A record of plan distribution is maintained by the S&OR Department.

PLAN RENEWAL & UPDATING PROCEDURES

The ODPCP is reviewed annually and revised and updated when changes occur. Below is a list of key factors that may cause revisions to the plan:

- New developments;
- Change to worst case discharge volume(s);

(b) (7)(F), (b) (3)

[redacted]

PIPELINES

NS26	WELL
	WELL SLOT
9	SURFACE ELEVATION
	SURFACE FLOW
	FIRE MONITOR STATIONS Level 2 Process Module and Along Pipe Rack

BP EXPLORATION (ALASKA) INC.

NORTHSTAR FACILITY
SEAL ISLAND

DATE:	SCALE:	FIGURE:
April 2011	1" = 100'	I-1

is2011_fms.mxd

PHMSA 000109274

- Change in commodities transported;
- Change in oil spill response organizations;
- Change in Qualified Individual;
- Change in a National Contingency Plan (NCP) or Area Contingency Plan (ACP) that has a significant impact on the appropriateness of response equipment or response strategies;
- Change in response procedures, and/or
- Change in ownership.

Routine updates are submitted for Alaska Department of Environmental Conservation (ADEC) review within 5 days after the date of a proposed change. Other modifications to the plan are considered amendments, reviewed and approved by ADEC.

Revisions to the plan are documented in the Record of Revisions table at the beginning of the plan and posted on the BPXA intranet site for BPXA employee and contractor reference. Hard copies of the changed pages or new CDs (for electronic copy holders) are distributed to plan recipients, including regulatory agencies and emergency operations centers. Upon receipt of revisions, the recipient replaces pages (hardcopy) or the previous CD, as instructed in the distribution letter. It is the responsibility of each plan recipient to ensure that updated pages are promptly incorporated into the plan and that previous CD revisions are discarded or archived.

Plan renewal cycles vary by government agency:

- ADEC (5 years)
- BSEE (5 years)
- USCG (5 years)
- DOT (5 years)

THIS PAGE INTENTIONALLY LEFT BLANK

STATE OF ALASKA

DEPT. OF ENVIRONMENTAL CONSERVATION
DEPARTMENT OF ENVIRONMENTAL CONSERVATION
DIVISION OF SPILL PREVENTION AND RESPONSE
INDUSTRY PREPAREDNESS PROGRAM

SEAN PARNELL, GOVERNOR

555 Cordova Street
Anchorage, AK 99501
PHONE: (907) 269-3094
FAX: (907) 269-7687
http://www.dec.state.ak.us

February 10, 2012

File Number 305.30
(BPXA Northstar)

OIL DISCHARGE PREVENTION AND CONTINGENCY PLAN APPROVAL

Michael Bronson
Eppie Hogan
BP Exploration (Alaska), Inc.
P.O. Box 196612
Anchorage, AK 99519-6612

Subject: **BP Exploration (Alaska), Inc. Northstar Oil Discharge Prevention and Contingency Plan, North Slope, Alaska. Plan Number 11-CP-4136. Plan Approval**

Dear Mr. Bronson and Ms. Hogan:

The Alaska Department of Environmental Conservation (department) has completed our review of your renewal application for the above referenced Oil Discharge Prevention and Contingency Plan (plan) dated May 2011. The department coordinated the State of Alaska's public review for compliance with 18 AAC 75, using the review procedures outlined in 18 AAC 75.455.

This approval applies to the following plan:

Plan Title:	**BP Exploration (Alaska), Inc. Northstar North Slope, Alaska, Oil Discharge Prevention and Contingency Plan**
Supporting Documents:	**Alaska Clean Seas Technical Manuals consisting of three volumes as revised and updated**
Plan Holder:	**BP Exploration (Alaska), Inc. P. O. Box 196612 Anchorage, AK 99519-6612**

Printed on Recycled Paper

Covered Facilities: **Production, Terminal, and Crude Oil Transmission Pipeline Operations**

PLAN APPROVAL: Approval of the referenced plan is hereby granted, **effective February 10, 2012.** A certificate of approval stating that the department has approved the plan is enclosed. **This approval is subject to the following terms and conditions:**

TERMS AND CONDITIONS

The following items must be completed and/or received as specified to complete the plan in accordance with AS 46.04.030(e).

1. **Notice of Changed Relationship with Response Action Contractor**. Because the plan relies on the use of response contractors for its implementation, BP Exploration (Alaska), Inc. (BPXA) must immediately notify us in writing of any change in the contractual relationship with the plan holder's response action contractors, and of any event including, but not limited to, any breach by either party to the response contract that may excuse a response contractor from performing, that indicates a response contractor may fail or refuse to perform, or that may otherwise affect the response, prevention, or preparedness capabilities described in the approved plan.

   This condition is reasonable and necessary because there are certain risks associated with allowing a plan holder to rely in part or total upon a response contractor instead of obtaining its own response capability. The risks arise, in part, because the certainty of the contractor's response is dependent upon the continuation of the legal relationship between it and the plan holder. Given this risk, the department must be promptly informed of any change of the contractual relationship between the plan holder and the response contractor, and of any other event that may arguably excuse the response contractor from performing or that would otherwise affect the response, prevention, or preparedness capabilities described in the approved plan. The department may seek appropriate modifications to the plan or take other steps to ensure that the plan holder has continuous access to sufficient resources to protect the environment and to contain, cleanup, and mitigate potential oil spills. 18 AAC 75.425(e)(3)(H) and 18 AAC 75.445(i).

2. **Blowout Contingency Plan.** A copy of the Blowout Contingency Plan must be maintained at Northstar facility and made available to the department upon request.

   This condition is necessary to ensure that the plan holder is prepared to control a potential well blowout. The department will review the blowout *contingency plan when performing site inspections. 18 AAC 75.425(e)(1)(I), 18 AAC.445(d)(2), and 18 AAC 75.480.*

3. **Final Copy of the Plan.** Within 30 days of this letter, the plan holder must submit to the department updated versions of the approved plan, including all revisions instituted during the recent plan review. BPXA must send two complete plan copies to the Exploration, Production & Refineries Section in Anchorage and one copy to the department's Fairbanks office. In addition, you must send an updated version of the plan to each reviewer and controlled document holder of your plan.

EXPIRATION: This approval **expires February 10, 2017**. After the approval expires, Alaska law prohibits operation of the facility until an approved plan is once again in effect.

AMENDMENT: Except for routine updates under 18 AAC 75.415(b), before a change to this plan may take effect, the plan holder must submit an Application for Amendment to the plan with any additional information needed to evaluate the proposed amendment. This is to ensure that changes to the plan do not diminish the plan holder's ability to respond to a discharge and to evaluate any additional environmental considerations that may need to be taken into account (18 AAC 75.415).

RENEWAL: To renew this approval, the plan holder must submit a completed renewal application and plan to the department no later than 180 days prior to the expiration of this approval. This is to ensure that the submitted plan is approved before the current plan in effect expires (18 AAC 75.420).

REVOCATION, SUSPENSION OR MODIFICATION: This approval is effective only while the plan holder is in "compliance with the plan" and with all of the terms and conditions described above. The department may, after notice and opportunity for a hearing, revoke, suspend, or require the modification of an approved plan if the plan holder is not in compliance with it, or for any other reason stated in AS 46.04.030(f). In addition, Alaska law provides that a vessel or facility that is not in "compliance with the plan" may not operate (AS 46.04.030). The department may terminate approval prior to the expiration date if deficiencies are identified that would adversely affect spill prevention, response, or preparedness capabilities.

DUTY TO RESPOND: Notwithstanding any other provisions or requirements of this plan, a person causing or permitting the discharge of oil is required by law to immediately contain and cleanup the discharge regardless of the adequacy or inadequacy of a plan (AS 46.04.020).

NOTIFICATION OF NON-READINESS: Within twenty-four (24) hours after any significant response equipment specified in the plan becomes non-operational or is removed from its designated storage location, the plan holder must notify the department in writing and provide a schedule for the equipment's substitution, repair, or return to service (18 AAC 75.475[b]).

CIVIL AND CRIMINAL SANCTIONS: Failure to comply with the plan may subject the plan holder to civil liability for damages and to civil and criminal penalties. Civil and criminal sanctions may also be imposed for any violation of AS 46.04, any regulation issued there under, or any violation of a lawful order of the department.

INSPECTIONS, DRILLS, RIGHTS TO ACCESS, AND VERIFICATION OF EQUIPMENT, SUPPLIES AND PERSONNEL: The department has the right to verify the ability of the plan holder to carry out the provisions of its plan and access to inventories of equipment, supplies, and personnel through such means as inspections and discharge exercises, without prior notice to the plan holder. The department has the right to enter and inspect the covered vessel or facility in a safe manner at any reasonable time for these purposes and to otherwise ensure compliance with the plan and the terms and conditions (AS 46.04.030[e] and AS 46.04.060). The plan holder shall conduct exercises for the purpose of testing the adequacy of the plan and its implementation (18 AAC 75.480 and 485).

FAILURE TO PERFORM: In granting approval of the plan, the department has determined that the plan, as represented to the department by the applicant in the plan and application for approval, satisfies the minimum planning standards and other requirements established by applicable statutes and regulations, taking as true all information provided by the applicant. The department does not warrant to the applicant, the plan holder, or any other person or entity: (1) the accuracy or validity of the information or assurances relied upon; (2) that the plan is or will be implemented; or (3) that even full compliance and implementation with the plan will result in complete containment, control, or cleanup of any given oil spill, including a spill specifically described in the planning standards.

The plan holder is encouraged to take any additional precautions and obtain any additional response capability it deems appropriate to further guard against the risk of oil spills and to enhance its ability to comply with its duty under AS 46.04.020(a) to immediately contain and clean up an oil discharge.

COMPLIANCE WITH APPLICABLE LAWS: If amendments to the approved plan are necessary to meet the requirements of any new laws or regulations, the plan holder must submit an application for amendment to the department at the above address. The plan holder must adhere to all applicable state statutes and regulations as they may be amended from time to time. This approval does not relieve the plan holder of the responsibility for securing other federal, state, or local approvals or permits, and the plan holder is still required to comply with all other applicable laws.

INFORMAL REVIEW OR ADJUDICATORY HEARING: Any person who disagrees with this decision may request an adjudicatory hearing in accordance with 18 AAC 15.195 - 18 AAC 15.340 or an informal review by the Division Director in accordance with 18 AAC 15.185.

Informal review requests must be delivered to the Division Director, 410 Willoughby Avenue, Suite 303, PO Box 111800, Juneau, Alaska 99811-1800 within 15 days of the permit decision.

Adjudicatory hearing requests must be delivered to the Commissioner of the Department of Environmental Conservation, 410 Willoughby Avenue, Suite 303, PO Box 111800, Juneau, Alaska 99811-1800, within 30 days of the permit decision. If a hearing is not requested within 30 days, the right to appeal is waived. Anyone who submits a request for an informal review or an adjudicatory hearing should also send a copy of the request to the undersigned.

If you have any questions, please contact Bob Tisserand at 269-3060.

Sincerely,

Betty Schorr

Betty Schorr
Program Manager

Attachment: Summary of Basis for Department Decision

Enclosure: Certificate of Approval, Number 12CER-007

Electronic cc w/o enclosure:

Scott Pexton, ADEC
Laurie Silfven, ADEC
Tom DeRuyter, ADEC
John Ebel, ADEC
Gordon Brower, NSB
Roy Varner, Sr., NSB
Hon. Charlotte Brower, NSB

Jake Adams, NSB
Richard Camilleri, NSB
Gordon Matumeak, NSB
Mike Thompson, JPO
Jack Winters, ADFG
Matt Carr, USEPA
Melanie Barber, USDOT
Pam Miller, Northern Alaska Environmental Center
Susan Harvey, Harvey Consulting
Legal Director, Trustees for Alaska
Samantha Carroll, ADNR
MST1 Brian Schughart, USCG Sector – Anchorage
LCDR Bradley Clare, USCG Sector – Anchorage
MSTC Shawn Erwin, USCG Sector – Anchorage
Christy Bohl, BSEE

ALASKA DEPARTMENT of Environmental Conservation

Certificate of Approval for

Oil Discharge Prevention and Contingency Plan

Certificate Number: **12CER-007**

Plan Number: **11-CP-4136**

Name of Plan: **BP Exploration (Alaska), Inc. Northstar Oil Discharge Prevention and Contingency Plan**

Covered Facilities: **Production, Terminal, and Crude Oil Transmission Pipeline Operations**

Address: **BP Exploration (Alaska), Inc., P. O. Box 196612, Anchorage, AK 99519-6612**

Telephone: **(907) 564-5111**

Fax: **(907) 564-5180**

Region of Operation (18 AAC 75.495): **North Slope, Alaska**

Effective Date of Approval: **February 10, 2012**

Expiration Date: **February 10, 2017**

This approval is subject to the terms and conditions of the applicable Alaska Department of Environmental Conservation contingency plan approval letter and continuing compliance with the requirements of AS 46.04 and 18 AAC 75.

Betty Schorr 02-10-2012

Betty Schorr, Approving Authority Date
Program Manager, Industry Preparedness Program

STATEMENT OF CONTRACTUAL TERMS

AS REQUIRED UNDER AS 46.04.30, AS 46.04.035 and 18 AAC 75.445(l) (1) in fulfillment of a requirement for registration of primary response action contractors and for approval of an Oil Discharge Prevention and Contingency Plan.

PLAN TITLE: Oil Discharge Prevention and Contingency Plan, Northstar Operations
PLAN HOLDER: BP Exploration (Alaska), Inc.

This statement is a certification to the Alaska Department of Environmental Conservation summarizing the contract between BP Exploration (Alaska), Inc. the oil discharge prevention and contingency plan holder (hereinafter "PLAN HOLDER") and Alaska Clean Seas, the oil spill primary response action contractor or a holder of an approved oil discharge prevention and contingency plan under contract (hereinafter "CONTRACTOR"), executed July 1, 2005, and the original of which is located at Alaska Clean Seas, 4220 B Street, Anchorage, Alaska, as evidence of the PLAN HOLDER's access to the containment, control and/or cleanup resources required under standards at AS 46.04.030 and 18 AAC 75.400 - 18 AAC 75.495. The PLAN HOLDER and the CONTRACTOR attest to the Department that the provisions of this written contract clearly obligate the CONTRACTOR to:

(A) provide the response services and equipment listed for the CONTRACTOR in the contingency plan;

(B) respond if a discharge occurs;

(C) notify the PLAN HOLDER immediately if the CONTRACTOR cannot carry out the response actions specified in this contract or the contingency plan;

(D) give written notice at least 30 days before terminating this contract with the PLAN HOLDER;

(E) respond to a Department-conducted discharge exercise required of the PLAN HOLDER; and

(F) continuously maintain in a state of readiness, in accordance with industry standards, the equipment and other spill response resources to be provided by the CONTRACTOR under the contingency plan.

I hereby certify that as a representative of the PLAN HOLDER, I have the authority to legally bind the PLAN HOLDER in this matter. I am aware that false statements, representations, or certifications may be punishable as civil or criminal violations of law.

Signature [signature] Date 7/14/05

Name: CRAIG L WIGGS

Title: DELIVERY UNIT MANAGER

For: BP Exploration (Alaska), Inc.
PLAN HOLDER

I hereby certify that as a representative of the CONTRACTOR, I have the authority to legally bind the CONTRACTOR in this matter. I am aware that false statements, representations, or certifications may be punishable as civil or criminal violations of law.

Signature [signature] Date 7/14/05

Name: Brad Hahn

Title: President

For: Alaska Clean Seas, CONTRACTOR

PART 1. RESPONSE ACTION PLAN
[18 AAC 75.425(e)(1)]

1.1 EMERGENCY ACTION CHECKLIST [18 AAC 75.425(e)(1)(A)]

Table 1-1 lists immediate response actions for an oil spill. Figure 1-1 provides a flow chart for immediate oil spill notification and reporting. Figure 1-2 and Table 1-2 illustrate the Incident Management Team (IMT) structure.

A spill response operation on the North Slope falls into one of three categories outlined below.

A Level I spill has limited duration and impacts, and can be handled by a BP Exploration (Alaska) Inc. (BPXA) response organization of immediately available local resources. Typical characteristics of a Level I spill are as follows:

- Less than one shift of the IMT in duration,
- Does not require mutual aid from other operators, and
- No written Incident Action Plan.

Level II and III spills activate the Greater Prudhoe Bay (GPB) IMT, shown in Table 1-2. A Level II spill is more complex, longer in duration, and characterized by more widespread effects. The Incident Command Post (location where the IMT operates) is located in the Prudhoe Bay Operations Center (PBOC). The activation of a BPXA response organization involves response resources available in Alaska. Typical characteristics of a Level II spill are as follows:

- More than one shift of the IMT in duration,
- Team members drawn from off-duty North Slope-based personnel and Anchorage-based personnel,
- Agency involvement and formation of a Unified Command, and
- Written Incident Action Plan.

A Level III spill is major, complex or compound in nature, has pronounced impacts on people, the environment, and/or property, and involves response operations for an extended period. A Level III spill involves the activation of all elements of the Incident Command System (ICS), supplemented by response resources from inside and outside of Alaska.

The response organization structure described in this plan is based on the ICS and accommodates each level of response. All three levels involve activation of the Spill Response Team (SRT), an IMT, and/or the Business Support Team. As necessary, BPXA uses the resources of other North Slope operators through Alaska Clean Seas (ACS), Mutual Aid, spill response cooperatives, and contractors.

TABLE 1-1: IMMEDIATE RESPONSE CHECKLIST

LEVEL I, II, & III SPILLS	
FIRST RESPONDER	☐ Assess safety of situation, determine whether source can be stopped, and stop the source of spill if possible. The first responder only takes action to the level they are trained to take. ☐ Immediately report the spill by calling Northstar Control Room at 670-3515 or calling on Northstar Harmony Channel 125. Immediately notify ACS and supervisory personnel after reporting the spill. ☐ Provide information on: • Personnel safety, • Source of the spill, • Type of product spilled, • Amount spilled, and • Status of control operations.
OPERATIONS SECTION CHIEF (DEPUTY OPERATIONS SECTION CHIEF DURING LEVEL II/III SPILLS)	☐ Report to scene. ☐ Make an initial assessment of the spill and associated safety and environmental issues. ☐ Stop the source of spill if possible. ☐ Initiate actions to report spill to agencies. ☐ Upon arrival on scene, begin response operations. If necessary, mobilize Spill Response Team and on-site equipment required to control and clean up spill. ☐ Assess response activities. If response is adequate, remain at Level 1. If additional capabilities are needed, go to Level II/III response. ☐ Supervise control and recovery operations. Upon completion, ensure appropriate storage and disposal of oily wastes/materials.
LEVEL II & III SPILLS	
INCIDENT COMMANDER (QUALIFIED INDIVIDUAL)/CONTROL ROOM The Northstar Offshore Installation Manager (OIM) serves as the Incident Commander/Qualified Individual.	☐ Immediately notify: • Spill Response Team • Environmental Advisor • Area Operations Manager North

TABLE 1-1 (CONTINUED): IMMEDIATE RESPONSE CHECKLIST

LEVEL II & III SPILLS (CONTINUED)	
SAFETY OFFICER	☐ Account for the safety of personnel. ☐ Ensure establishment of site-entry and exit procedures, including lower explosive limit (LEL) and air monitoring, and personnel and equipment decontamination. ☐ Determine if a threat of fire or explosion exists. If a threat exists, suspend control and/or response operations and notify Fire/Safety Department. ☐ Determine appropriate personal protective equipment (PPE) and brief site workers.
ENVIRONMENT TEAM	☐ Make immediate phone notification to the agencies. ☐ Initiate necessary permits for agency approval. ☐ Under GPB Environment Team oversight, prepare cleanup and waste management plan for agency approval. ☐ Ensure agency notifications are complete and maintain follow-up notifications on a periodic basis and whenever there is a significant change in the course of a reported incident.
INCIDENT COMMANDER / QUALIFIED INDIVIDUAL (IC/QI)	☐ Activate all or part of the IMT and the Command Post. ☐ Notify the BP Notification Center at 1-800-321-8642. The BP Notification Center will contact BPXA's Business Support Team Duty Officer and share information provided by the Incident Commander. Provide the BP Notification Center with a contact name and phone number. ☐ Continue internal and external notifications. ☐ Maintain communications with Anchorage Crisis Center. ☐ Coordinate staff activity. ☐ Manage incident operations and approve release of major resources and supplies.
OPERATIONS SECTION CHIEF	☐ Activate ACS 659-2405 (24 hours). ☐ Activate Mutual Aid through ACS as necessary. Establish staging areas as required. ☐ Provide the Logistics Section Chief with information on initial equipment, staff, material, and supply needs. ☐ Supervise control and recovery operations.

TABLE 1-1 (CONTINUED): IMMEDIATE RESPONSE CHECKLIST

LEVEL II & III SPILLS (CONTINUED)	
PLANNING SECTION CHIEF	☐ Ramp up Planning Section. ☐ Ensure Agency Notifications have been made and updates are provided. ☐ Compile and display status information in Command Post. ☐ Begin planning process. ☐ Document aspects of the response. ☐ Provide environmental support as needed.
LOGISTICS SECTION CHIEF	☐ Order equipment, personnel, material, and supplies as requested. ☐ Provide transportation support. ☐ Provide support for all field operations and Command Post operations.
FINANCE SECTION CHIEF	☐ Issue cost code for tracking of expenses. ☐ Notify insurance representatives as warranted. ☐ Track expenditures and provide audit function as needed.
DUTY OFFICER	☐ Activate Business Support Team as needed to support operation. ☐ Coordinate with the Incident Commander to mobilize backup resources. ☐ Activate the Anchorage Crisis Center to provide information distribution support. ☐ Coordinate Government and Public Affairs notification and information effort.

PHMSA 000109290

FIGURE 1-1: IMMEDIATE OIL SPILL NOTIFICATIONS

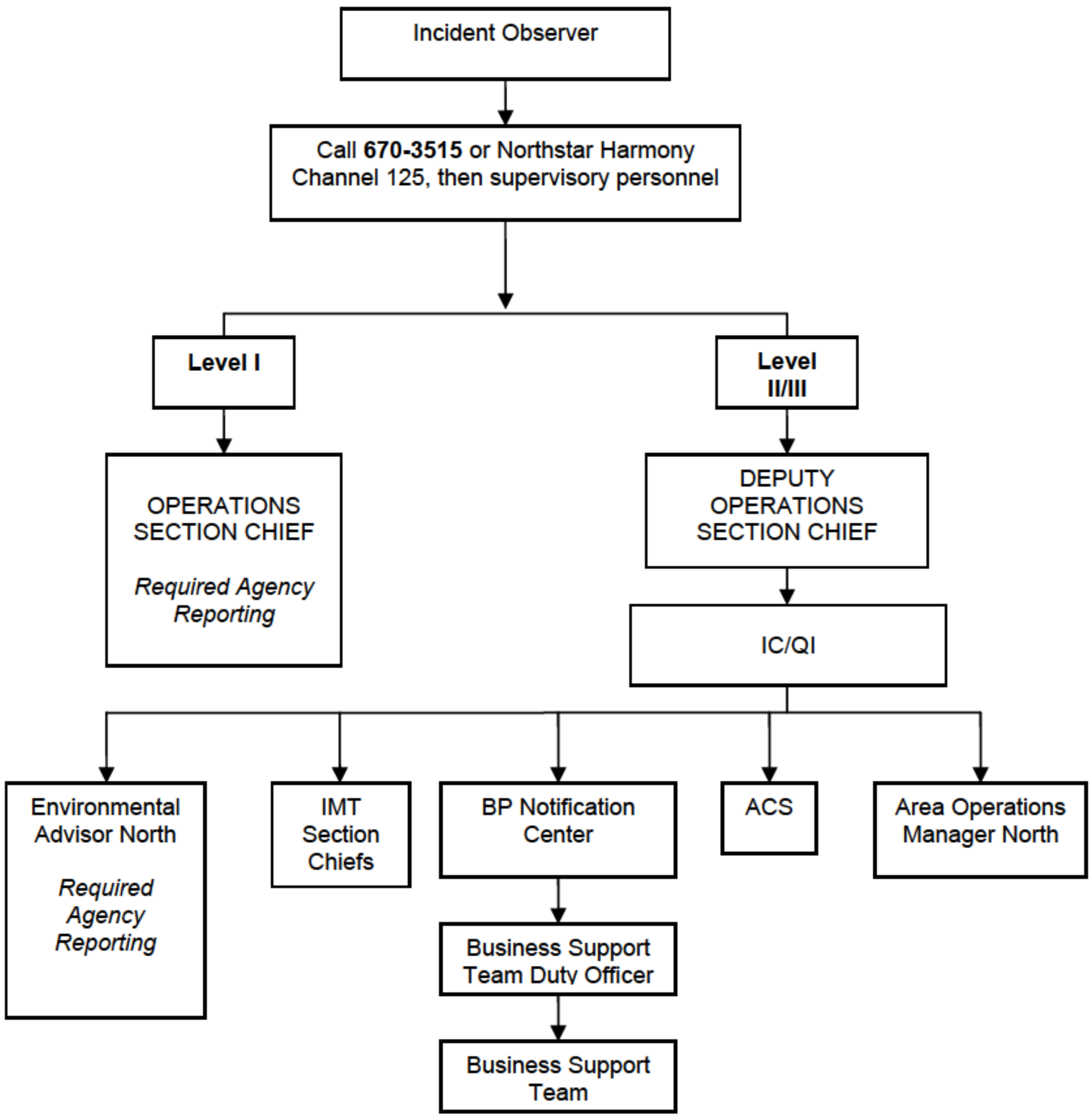
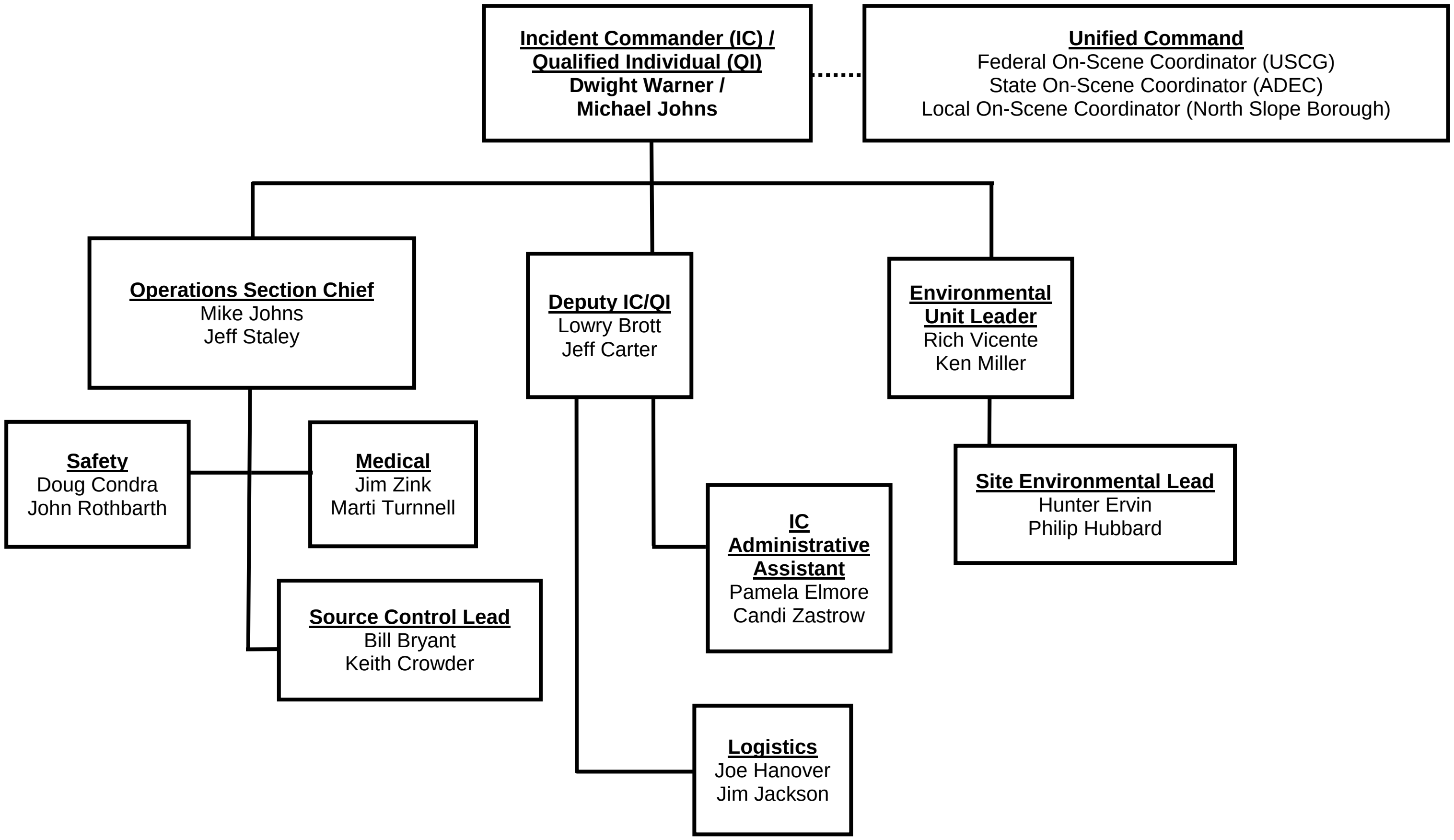


FIGURE 1-2: NORTHSTAR INCIDENT MANAGEMENT TEAM



The IMT is activated by dispatch via Harmony radio system at the direction of the Incident Commander.

TABLE 1-2: GPB INCIDENT MANAGEMENT TEAM

FACILITY	NAME	PHONE	INCIDENT COMMANDER	LOGISTICS SECTION CHIEF	PLANNING SECTION CHIEF	FINANCE SECTION CHIEF	OPERATIONS SECTION CHIEF
ALL	Shawn Croghan / TBD	659-4490	√				
ALL	Randy Sulte / Paul Jacobson	659-8185	√				
ALL	Michelle O'Malia/ Michael McKerrow	659-4270 659-8719		√			
ALL	Tom Barrett/ Chuck Wheat	659-5196			√		
ALL	Arvid Hall/ Brad Campbell/ Drais Farnham	564-5582 564-5836 564-4268				√	
GC1	James Fausett/ Scott Cabaniss	659-4476	√				√
	Joel Krueger/ Henry Smith	659-4087	√				√
GC2	Winston Shero/ Brett Leach	659-4902	√				√
	John Hanson/ Tom Simpson	659-4916	√				√
	Richard Fausett / Cam Smith	659-5934	√				√
GC3	Kurt Horst/ Christopher Rhoads	659-7790	√				√
	Scott Brown/ Cleve Pogue	659-4951	√				√
Flow Station 1 (FS1)	Mike Bolkovatz/ Dan Harris	659-8727	√				√
	Meredith Weinbrecht/ Mike Shelton	659-5392					√

TABLE 1-2 (CONTINUED): GPB INCIDENT MANAGEMENT TEAM

FACILITY	NAME	PHONE	INCIDENT COMMANDER	LOGISTICS SECTION CHIEF	PLANNING SECTION CHIEF	FINANCE SECTION CHIEF	OPERATIONS SECTION CHIEF
FS2 / COTU	Sohrab Tafreshi/ Brad Hobson	659-5489	√				√
	John Fejes/ Rick Bilstad	659-8423	√				√
	Skip Desaulniers/ Er k Painter	659-5492					√
FS3	Andy Burden / Mike Schoonmaker	659-5590	√				√
	Kevin Smith / Travis Rybicki	659-5592	√				√
	Jerem Feltman / JJ Johnson	659-8333	√				√
Lisburne Production Center (LPC) / GPMA	Jeff Clopton / Ned Kimball	659-8290	√				√
	Charlie Goff/ Bill Dawley	659-8667					√
	Taad Janson/Dale Sparks	659-8641					√
CPS	Jerome Hines/ Rob Kruger	659-4709	√				√
	Matt Brose/ Christopher Ori	659-4707					√
CCP / CGF	Tim Johnson/ Jeff Michels	659-5001	√				√
	Mitchell Wegner/ Jasper Covey	CCP 659-5362	√				√
	Carl Long / Mitchell Wegner	CGF 659-8682	√				√
STP / SIP	Nelson Martin/ TBD	659-8998	√				√
	Yancy Frahs/ Barry Durbrow	659-8492					√

1.2 REPORTING AND NOTIFICATION [18 AAC 75.425(e)(1)(B)]

1.2.1 INTERNAL NOTIFICATION PROCEDURES

It is BPXA policy for employees and contractors to report spills of oil or hazardous substances on BPXA leases regardless of size to a BPXA representative. See Table 1-1, Immediate Response Checklist. The Operations Section Chief or designee ensures that safety is considered and that internal notifications are made. See Table 1-3.

1.2.2 EXTERNAL NOTIFICATION PROCEDURES

The Environmental Advisor notifies regulatory agencies per the "BPXA North Slope Event Reporting, Clean-up, and Disposal Procedure." Agency notification requirements for oil spills are listed in Table 1-4. See Figure 1-3, North Slope Spill Report Form.

1.2.3 REPORTING REQUIREMENTS

Immediate reports are made to the National Response Center (NRC) and other agencies verbally, and contain the information sought on the NRC online reporting report (to the extent known at the time of initial notification) or on the form found in Figure 1-3.

Depending upon the type and amount of the release, individual government agencies have written reporting requirements. See Table 1-4.

Written reports include the following:

- Date and time of discharge;
- Location of discharge;
- Name of facility, vessel or pipeline;
- Weather conditions on scene;
- Name, mailing address, and telephone number of person or persons causing or responsible for the discharge and the owner and the operator of the facility, vessel or pipeline;
- Type and amount of each hazardous substance discharged;
- Cause of the discharge;
- Description of any environmental damage caused by the discharge, or containment, to the extent the damage can be identified;
- Description of cleanup actions taken;
- Estimated amount of hazardous substance cleaned up and hazardous waste generated;
- Date, location, and method of ultimate disposal of the hazardous substance cleaned up;
- Description of actions being taken to prevent recurrence of the discharge; and
- Other information the department requires to fully assess the cause and impact of the discharge.

TABLE 1-3: BPXA CONTACT LIST

POSITION	NAME	TELEPHONE**
VP Operations	Terry Welch	(907) 564-4877
Environmental Team Lead (North Slope)	Tom Barrett / Chuck Wheat	(907) 659-5196
ENDICOTT		
Endicott OIM / Qualified Individual	Rick Rodriguez / Gary Herring	(907) 659-6555
Endicott OTL / Alternate Qualified Individual	Paul Boots / Konrad Schruff	(907) 659-6527
Environmental Advisor North	Rich Vicente / Ken Miller	(907) 659-6810
ACS Environmental Tech. – Endicott	Greg Guild / Lance Douglas	(907) 659-6541
MILNE POINT UNIT (MPU)		
MPU OSM / Qualified Individual	Kenton Schoch / JoDee Johnson	(907) 670-3323
MPU Field OTL / Alt. Qualified Individual	Mark O'Malley / Rob Handy	(907) 670-3330
MPU Facility O&M TL / Alt. Qualified Individual	Gregg Alexander / Richard Knox	(907) 670-3331
Environmental Advisor MPU	Stefan Gogosha / Deb Heebner	(907) 670-3382
ACS Environmental Tech – MPU	Rob Murray / Neil Hermon	(907) 670-3473
NORTHSTAR		
Northstar OIM / Qualified Individual	Dwight Warner / Michael Johns	(907) 670-3576
Alt. Qualified Individual (GPB QI)	Shawn Croghan / TBD*	(907) 659-4490
Environmental Advisor North	Rich Vicente / Ken Miller	(907) 659-6810
ACS Environmental Tech – Northstar	Philip Hubbard / Hunter Ervin	(907) 670-3508
GREATER PRUDHOE BAY (GPB)		
Campaign Maint. OSM / Qualified Individual	Shawn Croghan / TBD*	(907) 659-4490
Inspection Exec. TL / Alt. Qualified Individual	Randy Sulte / Paul Jacobson	(907) 659-8185
Environmental Advisor West	Bill Fletcher / Steve McKendrick	(907) 649-4789
Environmental Advisor East	Beth Sharp / Eric Boyette	(907) 659-5999
Environmental Advisor Central	Geoff Kany / Alex Reyes	(907) 659-5893
Environmental Advisor – Functions	Natalia Lau / Trey Drake	(907) 659-4145
ACS Environmental Spill Technician – West	Fred Chace / Vic Richart	(907) 659-4375
ACS Environmental Spill Technician – East	Cory Settle / Heath Wilds	(907) 659-5800
ALTERNATE QUALIFIED INDIVIDUALS (ALL FIELDS)* NS Crisis Management Emergency Response Coordinator	Ed Wieliczkiewicz / Ken Uftkin	(907) 659-4106
WELL CONTROL SPECIALISTS Boots and Coots Services	(800) BLOWOUT / (800) 256-9688 (281) 931-8884	
ALASKA CLEAN SEAS, OSRO Prudhoe Bay Office, Pouch 340022 Prudhoe Bay, Alaska 99734	Ken Linderman / Fred McAdams, Operations Mgr.	(907) 659-2405
BP Notification Center (Naperville)		(800) 321-8642
**The numbers below are 24-hour spill reporting numbers. Qualified Individuals can be reached via these and/or the numbers above. Employees may also find additional contact information in the online Global Address List.		
Endicott		(907) 659-2222
Milne Point Unit		(907) 670-3300
Northstar		(907) 670-3515
Greater Prudhoe Bay		(907) 659-5700

O&M – Operations and Maintenance
OIM – Offshore Installation Manager
OSM – Onshore Site Manager
OSRO – Oil Spill Removal Organization
OTL – Operations Team Lead
TBD – To be determined
TL – Team Lead

TABLE 1-4: AGENCY REPORTING REQUIREMENTS FOR OIL SPILLS

AGENCY	LOCATION / RECEIVING ENVIRONMENT	SPILL SIZE	VERBAL REPORT	PHONE NUMBER	ALASKA CONTACT	WRITTEN REPORT
National Response Center (NRC) Notifies federal agencies as applicable. See specific federal agency below for guidance on reportable spill size.	Off pad to water or tundra	Any	Immediately	(800) 424-8802 (24 hr)	--	Not required – form is completed during phone notification process.
	To ice pad, ice road, or snow-covered tundra from an improperly functioning vessel/vehicle engine[1]	Any	Immediately			
U.S. Coast Guard (USCG)	In or threatening navigable waters	Any	Immediately	(907) 271-6700 (24 hr) (907) 271-6751 (FAX)	Anchorage Marine Safety Office USCG fax number	Not required but requested.
U.S. Department of Transportation (DOT), Pipeline and Hazardous Materials Safety Administration (PHMSA).	From a DOT-regulated pipeline and spill is not in or threatening navigable waters	≥5 gallons, resulting from an accident	Immediately[2]	(800) 424-8802	NRC and State Office of Pipeline Safety (Note: NRC notifies federal agencies)	Required within 30 days on DOT Form 7000-I (see form for details).
		≥210 gallons, resulting from pipeline maintenance activity[3]	Monthly written report			
	From a DOT-regulated pipeline and spill is in or threatening navigable waters	Any	Immediately	(800) 424-8802		Not required – form is completed during phone notification process
State Pipeline Coordinator's Office (Joint Pipeline Office) Anchorage, Alaska	Pipelines administered by the State Pipeline Coordinator's Office (SPCO) authorized under AS 38.35	Any	Immediately	(907) 257-1330 (direct) (907) 257-1300 (office) (907) 272-0690 (FAX)	M ke Thompson (State Pipeline Coordinator)	Not required.
U.S. Department of the Interior, Bureau of Safety and Environmental Enforcement (BSEE) Applicable to Endicott, Northstar and PM[2]	Marine waters	>42 gallons (1 barrel)	Immediately	(907) 334-5300 (24-hr) (907) 334-5302 (FAX)	Christy Bohl	Required within 15 days after spill is contained.
	All losses of well control	Any	Immediately			Required within 15 calendar days of incident

TABLE 1-4: AGENCY REPORTING REQUIREMENTS FOR OIL SPILLS

AGENCY	LOCATION / RECEIVING ENVIRONMENT	SPILL SIZE	VERBAL REPORT	PHONE NUMBER	ALASKA CONTACT	WRITTEN REPORT
Alaska Department of Environmental Conservation (ADEC)/Alaska Department of Natural Resources (ADNR)[4] ADNR has the same spill reporting requirements as ADEC[4]	Off pad to water or tundra	Any	Immediately (within 30 minutes)	ADEC (907) 451-2121 (907) 451-2362 (FAX) or Alaska State Troopers (800) 478-9300 (M-F after 5, Sat, Sun)	ADEC Tom DeRuyter ADEC fax number or Alaska State Troopers After-hours spills with immediate notification requirements	Required within 15 days after spill containment and cleanup are completed, or if no cleanup occurs, within 15 days after discharge or release.
	On gravel pad, gravel road, ice pad, ice road, or snow-covered tundra (Note: spills to snow, ice roads, and ice pads that do not penetrate to	<1 gallon	None			
		1 to 10 gallons	Monthly written report			
		>10 to 55 gallons	Within 48 hours			
		>55 gallons	Immediately			
	surface water or tundra are treated as spills to gravel pads)	>55 gallons	Within 48 hours	ADNR (907) 451-2678 (907) 451-2751 (FAX)	ADNR Spill Report Number ADNR fax number	
	Impermeable secondary containment areas or structures					
Alaska Oil and Gas Conservation Commission (AOGCC)	From wells or involving any crude loss Uncontrolled releases	Any >10 barrels or resulting in the shutdown of operations at production facilities	Immediately	(907) 279-1433 (24 hr) (907) 276-7542 (FAX) (907) 659-3607 (pager) (907) 659-2717 (FAX)	Dan Seamount John Norman Cathy Foerster	Required within 5 days of loss and Final report within 30 days

TABLE 1-4 (CONTINUED): AGENCY REPORTING REQUIREMENTS FOR OIL SPILLS

AGENCY	LOCATION / RECEIVING ENVIRONMENT	SPILL SIZE	VERBAL REPORT	PHONE NUMBER	ALASKA CONTACT	WRITTEN REPORT
North Slope Borough	Off pad to water or tundra	Any	Immediately	(907) 852-0440	Planning Department After hours Thomas Simmonds III: (907)306-9285 Ned Arey, Sr.: (907) 306-9732 Tony Cabinboy: (907) 306-6153	Copy of reports submitted as requested.
	On gravel pad, gravel road, ice pad, ice road, or snow-covered tundra	>55 gallons	Immediately			
	Impermeable secondary containment areas or structures	>55 gallons	Within 48 hours			

[1] "Discharges from a "properly functioning vessel engine" are not reportable to the NRC (exempt by 40 CFR 110.5). "Vessel" is defined as any artificial contrivance used or capable of being used as a means of transportation on water [33 U.S.C. §1311(a)(3)]. This includes trucks, rolling stock, and exploratory vehicles traveling on frozen tundra, but not equipment l ke light plants. Equipment used for traveling on ice roads, including vehicles, construction machinery, water trucks, and Rolligons, will be considered a "vessel" by EPA. "Improperly functioning" refers to mechanical problems such as a broken line or hose.

[2] The operator shall give verbal notice if the discharge:

- Caused a death or personal injury requiring hospitalization;
- Resulted in either a fire or explosion not intentionally set by the operator;
- Caused estimated property damage, including cost of cleanup and recovery, value of lost product, and damage to the property of the operator and/or others exceeding $50,000;
- Resulted in pollution of any stream, river, lake, reservoir, or other similar body of water that violated applicable water quality standards, caused a discoloration of the surface of the water or adjoining shoreline, or deposited a sludge or emulsion beneath the surface of the water or upon adjoining shorelines; and
- If, in the operator's judgment, it was significant even though it did not meet the criteria.

[3] No report is required for a discharge less than 5 barrels resulting from a pipeline maintenance activity if the discharge is:

- Not otherwise reportable;
- Did not result in pollution of any stream, river, lake, reservoir, or other similar body of water that violated applicable water quality standards, caused a discoloration of the surface of the water or adjoining shoreline, or deposited a sludge or emulsion beneath the surface of the water or upon adjoining shorelines; and
- Confined to company property or pipeline right-of-way and cleaned up promptly.

[4] The low concentrations and volumes of scale inh bitors, corrosion inhibitors, or biocides that are contained in and being used for their intended purpose in brines, seawater, produced water, drilling fluids, or crude oil do not trigger a spill reporting requirement. Rather, the requirement to notify ADEC of the release shall consider the parent material without the inclusion of these substances. As with all spill reports, all materials released must be included in the report whether or not they would, on an individual basis, trigger a reporting requirement to the State.

FIGURE 1-3: NORTH SLOPE SPILL REPORT FORM

Company:	Cause:
Contact:	
Phone Number:	
Spill Date:	
Spill Time:	Cleanup:
Location:	
Material Spilled:	
Amount:	
Area Affected:	Disposal:
Contained?	
Tundra or water affected?	
Weather Conditions? (temp, wind speed, skies)	
Comments:	
Time BPXA Person-in-Charge of Facility (Environmental Advisor) first obtained Knowledge of the Spill:	

Agency	Phone	Date	Time	Reported By	Reported To	Report Number
NRC (notifies EPA/ USCG/ USDOT/ BSEE) **(+ GPB see note below)** For DOT PL events, notify the BP DOT PL TL For BSEE events, notify Regional Supervisor.	(800) 424-8802					
ADEC After Hours (STATE TROOPERS)	(800) 478-9300					
ADEC During Business Hours	(907) 451-2121					
ADEC (sewage)	(877) 569-4114					
ADFG	(907) 459-7289					
ADNR	(907) 451-2678					
AOGCC (Anchorage)	(907) 279-1433					
AOGCC (Slope)	(907) 659-3607					
NSB During Business Hours	(907) 852-0440					
NSB After Hours	(907) 878-4843					
SPCO	(907) 257-1300					
BSEE (Notify for oil spills $\geq$1 bbl)	(907) 334-5300					
NPDES Hotline	(206) 553-1846					

Note FOR GPB ONLY: For spills reported to NRC and >10 gallons to water or tundra, or >55 gallons to gravel pad (includes snow, ice roads and ice pads), send an email or fax to Robbie Hedeen at EPA within 5 days (hedeen.roberta@epa.gov, fax 206-553-8509).

Done on Date: **Time:**

1.2.4 QUALIFIED INDIVIDUAL

In the event of a spill requiring notification of the NRC, the Environmental Advisor or designee ensures the designated QI is notified and is able to respond. In the event the primary QI is unavailable, the alternate QI will be contacted to respond. QIs are listed in Appendix A, Oil Pollution Act of 1990 Addendum.

The prerequisites for designation of a QI and/or roles and responsibilities can be found in 33 Code of Federal Regulations (CFR) 155.1026; 30 CFR 254.23; and 49 CFR 194. They include:

1. Available on a 24-hour basis,
2. Speak English fluently,
3. Located in the United States,
4. Trained as a Qualified and Alternate Qualified Individual under the response plan, and
5. Familiar with the emergency response plan and how to carry it out.

The QI must be trained and authorized to carry out the following responsibilities:

1. Activate and engage in contracting oil spill removal organization(s) and other response-related resources,
2. Act as a liaison with the Federal On-Scene Coordinator, and
3. Acquire funds to carry out response activities.

The QI and alternate QI are not responsible for:

1. The adequacy of the response plan prepared by the owner/operator, and
2. Acquiring funds for response resources beyond the full authority as designated by the owner/operator.

The QI or the QI's designee communicates to appropriate federal officials and response personnel if there is an oil spill requiring those communications (30 CFR 254.53(a)(2)). This communication requirement may be delegated as necessary (see Table 1-1).

At Northstar, the QI and the Incident Commander roles are filled by the Northstar Offshore Installation Manager (OIM).

1.3 SAFETY [18 AAC 75.425(e)(1)(C)]

The BP Control of Work Requirements was developed to reduce the number and frequency of injuries and serious incidents that occur in the workplace. The requirements ensure that there is a formal approach to managing work risks. The requirements are a procedural form of control, consisting of 12 elements supported by mandatory requirements. They cover the means of safely controlling construction, maintenance, demolition, remediation, operating tasks and similar work activities and apply to BP employees and every employee of any other company engaged to perform work on BPXA premises. The requirements are detailed in the *2010 BP Team Alaska Safety Handbook*. The handbook is distributed to BPXA employees and contractors.

The steps to develop an incident-specific safety plan are outlined in the ACS *Technical Manual*, Tactics S-1 to S-6. The ACS *Technical Manual*, Tactics S-1 through S-6, incorporated here by reference, includes site entry procedures, site safety plan (ICS Form 201-5) development, and personnel protection procedures.

The BPXA well plan prepared for each drilling operation conducted on the North Slope is designed to ensure drilling activities are performed in a safe and environmentally sound manner. Each plan identifies the procedures, systems, and equipment employed in drilling; uses the best technical information available concerning subsurface formation characteristics and pressures; and provides information critical to the success and safety of the drilling program.

Emergency response procedures are in place for evacuation in and around the facility in the event of a discharge or release of stored materials. The location of stored materials is presented in Part 3 and Appendix A. Hazards posed by discharged materials and a discussion of discharge flow direction, prevailing wind direction and speed, receiving environment, and emergency response actions are presented in the response scenarios in Part 1, and in tables and language in Parts 2 and 3.

Emergency response procedures are located on the BPXA intranet and are available to employees and contractors. The procedures cover alarm and notification systems, primary and alternate evacuation routes, designated safe areas, roll-call procedures, and initial identification and treatment of injured personnel, including transportation to medical facilities.

1.4 COMMUNICATIONS [18 AAC 75.425(e)(1)(D)]

The communications plan is designed for compatibility with the communications equipment available through BPXA's Anchorage office, BPXA's North Slope facilities, and ACS. Initially, Northstar will respond to incidents using the day-to-day communications system. Northstar has on site, at a minimum, the following radio equipment:

- Very High Frequency (VHF) oil spill repeater;
- Transmission line with connectors;
- VHF antenna;
- Tone remote controls (two each);
- Marine private coast station;
- VHF handheld radios (six each);
- Backboarded Spectra mobile radio, and
- Satellite phones.

Northstar uses the Eastern GPB repeater located at the Lisburne Production Center (LPC). The repeater provides for direct tie-in to the ACS communications system. With such repeaters installed across the North Slope, coverage is provided from Alpine to Badami. The range of each fixed repeater is approximately 10 to 20 miles depending on topography and antenna height. Microwave relays in Prudhoe Bay give an effective range of 30 to 50 miles. ACS solar-powered or generator-powered portable repeaters can also be deployed at the time of a spill. ACS will provide the repeater, coast station, antennas, handheld radios, and backboarded mobiles to allow for effective spill response, when necessary, in an emergency. Radio communications equipment is presented in Table 1-5.

TABLE 1-5: RADIO COMMUNICATIONS EQUIPMENT

CHANNEL NUMBER	USE	LOCATION	EQUIPMENT TRANSMITS (MHZ)	EQUIPMENT RECEIVES (MHZ)
OS-39	Oil Spill Repeater	Prudhoe Bay (Lisburne/Northstar)	158.325	153.185
OS-86	Coast Station Ch 80A	Northstar/Alpine	157.025	157.025

Spill response vehicles and the Mobile Command Center are equipped with frequency-agile, high-band VHF and ultra high frequency (UHF) radios. This capability coordinates the SRT with the North Slope Operating Area frequency plan, and includes access to mobile communication channels. Vehicles assigned to fire or medical responses are equipped with a Harmony radio system.

Mobile telephone services form an important part of the spill response communications. The Mobile Command Center, SRT Commander's truck, both Autocar™ tractors, SRT Tech truck, and Spill Van all have radio and bag phones available. If necessary, there is also a Harmony radio system available for use. The SRT Command Van also has a permanently installed Bush Phone to provide a telephone line for a mobile fax machine. Finally, a portable two gigahertz (GHz) microwave shelter housing a six-channel microwave system has been mounted on a small vehicle trailer to provide communications to the mobile Staging Area Manager's Office. This includes one serial computer link with access to the computer network, one telephone line to connect a facsimile machine, and four standard telephone lines.

A detailed explanation of oil spill communications on the North Slope is provided in the ACS *Technical Manual*, Tactic L-5, incorporated here by reference.

1.5 DEPLOYMENT STRATEGIES [18 AAC 75.425(e)(1)(E)]

In this plan, mobilization means readying for travel. Deployment means readying for use at the site. Travel time is the period between mobilization and deployment.

Initial spill response transportation relies on the BPXA daily operations infrastructure. The extensive transportation infrastructure of personnel and equipment can support a small response and be enhanced for a major spill. Transportation options provide alternative methods in adverse weather. Options are summarized in Table 1-6.

TABLE 1-6: SEASONAL TRANSPORTATION OPTIONS

MODE	SEASONS		
	SUMMER	WINTER	BREAK-UP / FREEZE-UP
Vessels	X		Partial
Helicopters	X	X	X
Fixed-wing aircraft		X	
Vehicles		X	
Heavy all-terrain vehicles (Arctos)	X	X	X
Air boats	X	X	

The seasons listed in Table 1-6 are defined by sea surface conditions. They are described in detail in Sections 3.2 and 3.4 (DF Dickins et al., 2000, pp. 2-2 to 2-8). Freeze-up around Northstar generally begins about October 6. The ice typically becomes stable in mid-November, the point when freeze-up ice conditions can be considered as changing to winter ice conditions. Winter ice conditions, characterized by stable, fast consolidated ice, transition to break-up conditions with river overflooding, meltpools and decaying ice in late May. Break-up continues until open water (i.e., less than 10 percent ice coverage) typically beginning in mid-July. Summer spans the open water period until October.

The ACS *Technical Manual* Tactics L-3, L-4, and L-6 provide detailed information on transportation procedures. Their transportation information is incorporated here by reference.

Year-round air access to the Northstar field area is available. Northstar has a 55-foot square heli-deck that can accommodate landings of medium lift helicopters. Air operations can be limited by weather conditions. They are suited for movement of personnel and emergency movement of supplies or equipment to the field.

Air transportation to Northstar is provided year round by a contracted helicopter. Alyeska Pipeline Service Company also has a Bell 206-L helicopter on contract available to BPXA upon request. The helicopter is based at Pump Station 4.

Sea ice access is by winter ice roads. Ice roads are commonly used on the North Slope for winter travel from late December through mid-June for specific projects. Vehicle access across the sea ice can continue after the ice road season by means of tracked vehicles through June (Coastal Frontiers Corporation, 2001).

Marine vessel access is available from July through September. BPXA and ACS have contracts in place with the major North Slope marine contractors.

ACS is the primary response action contractor for BPXA. The 24-hour phone number for ACS is listed in Table 1-3.

Section 1.1 describes immediate response and notification actions, including notification of ACS. While ACS is mobilizing personnel and equipment to the spill site, on-site BPXA and ACS personnel will determine safety procedures, notify government agencies and BPXA personnel, and proceed with source-control measures. Off-site BPXA personnel may be consulted as necessary.

1.6 RESPONSE SCENARIOS AND STRATEGIES [18 AAC 75.425(e)(1)(F) AND 18 AAC 75.445(d)]

1.6.1 QUALIFIER STATEMENT

Scenarios are developed in accordance with 18 Alaska Administrative Code (AAC) 75.425(e)(1)(F) and (I), 18 AAC 75.445(d). They describe equipment, personnel, and strategies that could be used to respond to an oil spill. The scenarios describe oil spill recovery by 100% mechanical means, as required by 18 AAC 75.425(e)(1)(F)(vii).

The scenarios are for illustration only and are not performance standards or guarantees of performance. Actual responses in an oil spill emergency depend on personnel safety considerations, weather and other environmental conditions, agency permits and priorities, and other factors. In an incident, considerations to ensure the safety of personnel will be given highest priority. The scenarios assume conditions only for the purposes of describing general procedures, strategies, tactics, and selected operational capabilities. The scenarios assume the agency on-scene coordinators and other agency officials will immediately grant required permits.

Although equipment is specified in the scenarios, it may be replaced by functionally similar equipment in the future. The response timelines are for illustration only. They do not limit the discretion of the people in charge of the spill response to select a specific sequence or take the time they deem necessary for an effective response without jeopardizing safety.

Some scenarios simulate heavy equipment operators, e.g., truck drivers and front end loader operators. Staff in the *equipment operator* category typically operate their equipment on a regular schedule on the North Slope unrelated to spill responses and are not members of the North Slope Spill Response Team (NSSRT).

In situ burning could be used in a spill response to reduce the quantity of oil, regardless of whether a scenario hypothesizes in situ burning.

The response strategies illustrate tactics to account for variations in receiving environments and seasonal conditions [18 AAC 75.425(e)(1)(F)].

1.6.2 WASTE DISPOSAL APPROVAL

The method of disposal for oil and contaminated materials from oil spill recovery operations must be approved by state and federal agencies before implementation. At the time of the spill, the Operations Section Chief, in consultation with the Environmental Unit Leader, will determine a reuse, recycle, or disposal method best suited to the condition of the oil, the degree of contamination of recovered debris, and the logistics involved. See Tactics D-1 through D-5 in the ACS *Technical Manual*.

When an IMT is not involved, spills of crude oil and exempt hazardous substances of 200 gallons or less to gravel pads, roads, ice roads or ice pads can automatically use pre-approved permitted storage and disposal facilities. For spills above the threshold level, or to other receiving environments, approval for storage and disposal will be obtained from the State On-Scene Coordinator before material is removed to those facilities. The approval can be in the form of a verbal communication during initial spill notification.

An initial determination of exempt, hazardous, or non-hazardous must be made for classification of the waste. This classification must be made on a case-by-case basis. The Environmental Unit Leader will provide assistance in determining the classification should the status of the waste material be in question. The applicable guidelines are listed below.

- Spills from common carrier transportation pipelines are non-exempt, and it must be determined whether the material to be disposed of is hazardous;
- Spilled material that comes out of a well, either during drilling or workover operations, is exempt. Spilled material that did not come out of a well is non-exempt, and it must be determined whether the material to be disposed of is hazardous; and
- Spills of non-exempt fluids that occur during filling a tank (e.g., vehicle, storage, etc.) are non-exempt, even though they may occur on a well pad, and it must be determined whether the material to be disposed of is hazardous.

The preferred management option for recovered oil and diesel is to recycle it back into the production stream. If the material is not suitable for recycling, it will be determined whether it is hazardous. If hazardous, it will be placed in drums and stored on site until it is shipped to an approved hazardous waste treatment, storage, or disposal facility. The Environmental Advisor will determine the appropriate management method.

Guidelines for handling and managing oil and contaminated materials from oil spill recovery operations or for oily waste from normal operations are found in the "Alaska Waste Disposal and Reuse Guide."

1.6.3 RESPONSE SCENARIOS AND STRATEGIES

Response scenarios and strategies are presented in this section. The scenarios show that the plan meets the Response Planning Standard (RPS) volumes described in Part 5.

- Scenario 1: Oil Storage Tank Rupture
- Scenario 2: Well Blowout Under Typical Summer Conditions
- Scenario 3: Well Blowout Under Typical Winter Condition
- Scenario 4: Crude Oil Transmission Pipeline Release
- Response Strategy #1: Well Blowout During Typical Spring Conditions
- Response Strategy #2: Crude Oil Transmission Pipeline Rupture During Spring Break-Up

- Response Strategy #3: Crude Oil Transmission Pipeline Rupture During Summer
- Response Strategy #4: Crude Oil Transmission Pipeline Rupture During Fall
- Response Strategy #5: Crude Oil Transmission Pipeline Rupture During Winter

THIS PAGE INTENTIONALLY LEFT BLANK

SCENARIO 1

OIL STORAGE TANK RUPTURE

THIS PAGE INTENTIONALLY LEFT BLANK

TABLE 1-7: OIL STORAGE TANK RUPTURE SCENARIO CONDITIONS

PARAMETER	PARAMETER CONDITIONS
Spill Location	Northstar Production Island
Spill Date and Time	July 15, 6:00 a.m.
Cause and Source of Spill	Diesel storage tank failure, Tank T-S3-8202
Quantity of Spill	Adjusted RPS volume = 758 barrels (bbl) which are released from the storage tank. No oil reaches open water. Refer to Part 5 for detailed explanation of RPS.
Weather	Overcast, 48 F
Visibility	Two miles
Wind Direction and Speed	>10 knots, wind from the WNW
Spill Trajectory	Of the 758 barrels that escape the oil storage tank, 100 barrels remains in the tertiary containment area and 298 barrels are contained within the tank truck loading area, leaving 360 barrels to flow across the gravel pad and under the module. Assuming an absorption rate of 0.125 bbl per cubic yard (ACS Technical Manual Tactic R-5), the spill impacts approximately 2,880 cubic yards of gravel. See Figure 1-4. No oil enters open water.

TABLE 1-8: OIL STORAGE TANK RUPTURE RESPONSE STRATEGY

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(i) Stopping Discharge at Source	A plant operator requests lines flowing into the tank be closed. The tank shut-in procedure is evaluated to ensure possible sources have been secured. Notification procedures begin, along with SRT mobilization. A staging area and field command post are established. Within the first few hours of the spill, production supervisors prepare a team to perform repairs to the tank, and initiate fluid transfer from the damaged tank to the process stream.	A-1, A-2, L-2 BPXA Incident Management System (IMS) Manual
(ii) Preventing or Controlling Fire Hazards	Throughout the first few hours of the spill, the On-Scene Commander with the assistance of the Site Safety Officer verifies that sources of ignition are shut down or removed from the area. The Site Safety Officer and Operations Section Chief perform a visual inspection of the tank and a site safety assessment. After declaring the area clear, the Safety Officer begins to prepare a site safety plan (ICS Form 201-5) including PPE requirements. The first draft of site safety plan focuses on the delineation, containment and source control teams. It quickly evolves to include spill recovery teams. Access to the spill site is carefully controlled and the scene is secured by designated personnel. Monitoring protocol is established by the Site Safety Officer for all work areas to ensure personnel protection.	S-1 through S-6
(iv) Surveillance and Tracking of Oil; Forecasting Shoreline Contact Points	Once safety zones and a decontamination unit have been set up by Hour 4, the contaminated area is delineated. The extent of oil on the pad and tundra is delineated on land with lathe and/or hand-held global positioning systems (GPS) units.	T-1, T-2
(v) Protection of Environmentally Sensitive Areas and Areas of Public Concern	The Environmental Unit Leader identifies priority protection sites, relying on the ACS *Technical Manual* descriptions and the Alaska Regional Response Team's North Slope Subarea Plan list of areas of major concern. No priority protection sites are within the plume. The area is monitored for birds that may be at risk from the spill throughout the spill response.	W-6, ACS Map Atlas Sheet 99
(vi) Spill Containment and Control Actions	By Hour 4, the decontamination area is set up. By Hour 5, berms are constructed around the soiled perimeter of the spill to deflect and contain diesel.	C-4
	A staging area is established in the southeastern part of the production pad by Hour 4.	L-2

TABLE 1-8 (CONTINUED): OIL STORAGE TANK RUPTURE RESPONSE STRATEGY

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(vii) Spill Recovery Procedures	Starting on Day 1, crews set up hoses and pumps in series to collect diesel from pad depressions and the tertiary containment area.	R-24
	Starting on Day 2, after a majority of the liquid phase recovery is complete, contaminated gravel from the pad and the tank truck loading area is recovered with a front-end loader and hauled to a stockpile. Hand shovelers also recover contaminated gravel from underneath the module.	R-26
	Gravel areas are cleaned over 30 days to the satisfaction of ADEC.	R-9, R-26
(viii) Lightering Procedures	Not applicable.	Not applicable
(ix) Transfer and Storage of Recovered Oil/ Water; Volume Estimating Procedure	Recovered diesel suitable for freeze-protection is stored on site for later use or is processed through Northstar's processing center for hydrocarbon recycling.	D-1
	Diesel volume in solids is estimated with grab samples. Oiled gravel is stockpiled in the lined containment cell (20' x 10' x 4' = 800 ft^3) on the north side of the island. An additional containment cell (75' x 10' x 4' = 3,000 ft^3) is constructed on the southeastern part of the pad.	D-4
(x) Plans, Procedures, and Locations for Temporary Storage and Disposal	The Waste Management Team completes the following tasks: 1. Fill out and sign manifests, 2. Measure liquid and other waste, and 3. Submit a plan to ADEC for waste management. Unsuitable diesel that tests hazardous is drummed, stored and then shipped to an EPA-approved disposal facility.	D-1
	Used sorbents are collected in plastic bags or other leak-proof storage containers, barged and disposed of by incineration in Deadhorse.	D-2
	Contaminated gravel is stockpiled in the lined, bermed containment areas on site until it can be transported to GPB Grind and Inject (G & I) facility via the ice road in winter.	D-4
(xi) Wildlife Protection Plan	Immediate response activities include the preparation of wildlife deterrent systems. The area is monitored for birds and mammals that may be at risk from the spill throughout the spill response.	W-1, W-2B, W-3, W-4
(xii) Shoreline Cleanup Plan	Not applicable.	Not applicable.

TABLE 1-9: OIL STORAGE TANK RUPTURE OIL RECOVERY CAPABILITY

A SPILL RECOVERY TACTIC, ACS TECH MANUAL TACTICS DESCRIPTION	B NUMBER OF RECOVERY SYSTEMS	C RECOVERY SYSTEM	D DERATED OIL RECOVERY RATE PER UNIT BARRELS PER HOUR (BOPH) OR CUBIC YARDS (YD^3)	E MOBILIZATION, DEPLOYMENT AND TRANSIT TIME TO SITE[1] (HOURS)	F OPERATING TIME (HOURS PER 24-HOUR SHIFT)	G OIL RECOVERY CAPACITY (BOPD OR YD^3) B X D X F
R-24	1	3" Diaphragm Pump with 3" Suction and 3" Discharge Hoses	357[2]	5	20	7,140
R-24	1	2" Trash Pump with 2" Suction and 2" Discharge Hoses	314[3]	5	20	6,280
R-26	1	Front-end Loader	9[4]	Day 2	20	180

[1] The sum of the mobilization, deployment, and transit time is not the fastest time poss ble; rather, it is the time that each specific tactic is first employed in this specific scenario.

[2] Diaphragm pump pumping capacity of 250 gallons per minute (gpm) / 42 gallons x 60 minutes = 357 boph. See Tactic L-6.

[3] Trash pump pumping capacity of 220 gpm / 42 gallons x 60 minutes = 314 boph. See Tactic L-6.

[4] Loader recovery calculation: Tc/(Lt+Tt+Ut) = 3 yd3/[0.25 hour + (0.08 mile from spill site to stockpile site x 2 trips/10 mph) + 0.08 hour] = 9 yd3/hour, where,
Tc = Loader Capacity
Lt = Load Time
Tt = Travel Time
Ut = Unload Time

PHMSA 000109316

TABLE 1-10: OIL STORAGE TANK RUPTURE
MAJOR OIL CONTAINMENT AND RECOVERY EQUIPMENT EQUIVALENTS

RECOVERY TACTIC	NO. TACTICAL UNITS	EQUIPMENT PER TACTICAL UNIT	TOTAL QUANTITY
C-4	1	Loader	1 Loader
R-24	1	3" Diaphragm Pump 2" Trash Pump 2" and 3" Suction Hose 2" and 3" Discharge Hose Fastank	1, 3" Diaphragm Pump 1, 2" Trash Pump Suction Hose Discharge Hose 1 Fastank
R-26	1	Loader	1 Loader

TABLE 1-11: OIL STORAGE TANK RUPTURE
PERSONNEL TO OPERATE OIL CONTAINMENT AND RECOVERY EQUIPMENT

LABOR CATEGORY	TACTIC	NO. TACTICAL UNITS	NO. STAFF PER UNIT	DAY 1, NO. STAFF PER SHIFT	DAYS 2-30, NO. STAFF PER SHIFT
Equipment Operator	C-4	1	1	1	0
	R-26	1	1	0	1
Team Leader	R-26	1	1	1	1
General Technician	R-26	1	6	6	6
			Total	8	8

(b) (7)(F), (b) (3)

[redacted]

PIPELINES

NS26 WELL

WELL SLOT

9 SURFACE ELEVATION

SURFACE FLOW

FIRE MONITOR STATIONS
Level 2 Process Module and
Along Pipe Rack

BP EXPLORATION (ALASKA) INC.

NORTHSTAR OIL STORAGE
TANK RUPTURE
LOCATION MAP

DATE:	SCALE:	FIGURE:
February 2011	1" = 100'	1-4

is2011_fms.mxd

SCENARIO 2

WELL BLOWOUT UNDER TYPICAL SUMMER CONDITIONS

THIS PAGE INTENTIONALLY LEFT BLANK

TABLE 1-12: WELL BLOWOUT UNDER TYPICAL SUMMER CONDITIONS SCENARIO CONDITIONS

INITIAL CONDITIONS	
Spill Location	Northstar Production Island, Well NS-30
Spill Date and Time	August 1, 12:00 am, 15 days
Cause and Source of Spill	Although the production wells have blowout preventers and are covered with a well house, this scenario assumes an uncontrolled well blowout occurs through an unobstructed, open orifice.
Quantity of Oil Spilled	2,295 barrels of oil per day (bopd) is discharged for 15 days The total quantity released is 34,425 barrels Northstar crude
Typical Summer Weather	Sunny, 40 F, visibility is <1/2 nautical mile 18 percent of the time. No ice coverage 1/10 or greater.
Sea Surface	Sea surface current is wind-driven and deflected by shorelines.
Average Wind Speed and Predominant Direction	During summer, the average wind speed is 11 knots. The predominant wind directions were determined as the 16 cardinal compass directions that blow over 10 percent of the time. For May to October, the predominant wind directions at Northstar are from the east-northeast and east. See Figure 1-5. The wind data were retrieved from the Nearshore Beaufort Sea Meteorological Monitoring and Data Synthesis (Veltkamp, B. and Wilcox, 2007). The weather data presented were collected during the summers of 2000 through 2006.
Spill Trajectory	The discharged oil takes the form of an aerial plume extending from the well to the west-southwest and west with the direction of prominent winds (ACS *Technical Manual* Tactic T-6). The S.L. Ross model (1997) indicates that 10 percent of the discharged oil is in the form of drops so small (50 µm or less) that they do not fall to the ground but are held aloft by atmospheric turbulence. For response planning purposes, the oil predicted by the model to remain airborne is proportionally distributed within the projected blowout plume footprint. The scenario location was selected per ADEC regulations (18 AAC 75,434(e)). Well NS-30 was the highest producing well according to AOGCC's production reports from January 2010 through December 2010. Simulated oil flows from the 4-inch (inner diameter) open orifice well at the rate of 2,295 bopd with gas-to-oil ratio (GOR) of approximately 20,670 standard cubic feet per barrel. In these circumstances, the dimensions of the blowout footprint represent the maximum gas flow through a 4-inch (inner diameter) opening. The maximum plume dimensions are 4.9 miles long and 0.7 miles wide. See Figure 1-6. Approximately 15 percent (5,320 bbl) of the oil falls to the Northstar production island. Approximately 80% of the discharged oil falls within 0.7 miles of the well. If left unrecovered for 15 days, the average thickness of the discharged oil deposited between 0.7 and 4.9 miles is 0.003 inches. This sheen would be visible as a blue-black sheen on the water surface (ACS *Technical Manual* Tactic T-7.) The oil is deposited into two plumes over a 15 day period. The volumes deposited are projected to be the following: Days 1 to 9.1 20,970 bbls are deposited to the west-southwest Days 9.2 to 15 13,455 bbls are deposited to the west After it has been deposited to the ocean surface, oil forms into windrows. Floating oil moves at the same speed as the underlying water plus three percent of the wind speed. The direction and speed of the oil can be predicted by vector addition. (See ACS *Technical Manual* Tactic T-5, incorporated by reference.)

TABLE 1-13: WELL BLOWOUT UNDER TYPICAL SUMMER CONDITIONS RESPONSE STRATEGY

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(i) Stopping Discharge at Source	The On-Site Company Representative takes the roll of Initial On-Scene IC, calls the emergency phone number, and notifies the Drilling Superintendant, NS Well Operations Team lead, and the affected Alaska Drilling and Wells (ADW) Team Lead. The IMT is activated. The affected ADW Well Manager calls well control specialists to obtain guidance for source control. Production is shut down, closing in the wells at the surface and subsurface. The Operations Team Lead assumes Surface Control leadership and plans initial surface controls.	A-1, A-2, L-2 BPXA IMS Manual
(ii) Preventing or Controlling Fire Hazards	The Operations Section Chief sets up access zones and routes and firefighting operations to protect assets and workers. Throughout the first few hours of the spill, the Operations Section Chief, with the assistance of the Site Safety Officer and Fire Chief, verify no ignition sources in the area. The Site Safety Officer determines response workers' PPE needs and provides hot and warm zone access information. The first draft of site safety plan (ICS Form 201-5) focuses on the delineation, containment and source control teams. It quickly evolves to include spill recovery teams. Monitoring protocol is established by the Site Safety Officer at work areas for personnel protection. The monitoring protocol establishes safety zones according to applicable Occupational Safety and Health Administration (OSHA) and fire hazard standards. Containment and recovery operations are conducted in accordance with site entry procedures. Recovery operations and oil field operations are disallowed downwind of the blowout well in areas where personnel may become exposed to flash fire hazard or oil particulate matter at concentrations greater than permissible exposure limits. Firewater coverage is set up by source control specialists.	S-1 through S-6
(iv) Surveillance and Tracking of Oil; Forecasting Shoreline Contact Points	By Hour 4 an aircraft is dispatched to monitor for oil. The slick is tracked by the aircraft, which records with a forward looking infrared radar (FLIR) system. Approximately 4 hours after the aircraft has finished the survey, the infrared data is overlain on a digital map of the area, resulting in a detailed map of the spill. The system works during day or night conditions. The deployment of tracking buoys is considered. The buoys are capable of transmitting position information and other pertinent data to satellites for retransmission to Unified Command. Field data are used to periodically update the trajectory maps.	T-4 through T-7

TABLE 1-13 (CONTINUED): WELL BLOWOUT UNDER TYPICAL SUMMER CONDITIONS RESPONSE STRATEGY

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(v) Protection of Environmentally Sensitive Areas and Areas of Public Concern	The Unified Command approves the activities and tactics used to protect environmentally sensitive areas and areas of public concern. **Priority Protection Sites.** Based on the Alaska Regional Response Team's (ARRT's) "North Slope Sub-Area Plan," the barrier islands from Long Island to Bodfish Island are identified as environmentally sensitive areas and areas of public concern. See Figure 1-6.	W-6
	Protection Strategies. The Environmental Unit issues an advisory with the concurrence of the State Historic Preservation Officer. The Operations Chief directs that crews avoid the cultural sites as noted by the ACS *Technical Manual* Map Atlas and Alaska Heritage Resource Survey data. Catalogued cultural resource sites are listed on the maps that cover their vicinity in the spill area. The *Technical Manual* lists are adapted from the "North Slope Subarea Plan."	Map Atlas Sheets 33, 34, 38, 56, 57 and 58
	The first strategy to protect environmentally sensitive areas and areas of public concern by mechanical response is to remove oil quickly and where it still lies in thick layers close to the spill source. Targeting that area can most effectively reduce the quantity of oil available to move into sensitive areas later. A further strategy is to deploy deflection boom at selected shoreline sites in the path of the oil. **Shoreline Protection: Task Force 1.** Two airboats tow boom from West Dock and anchor it in shallow water. See Figure 1-6. Deflection booming tactics, including equipment lists, personnel numbers, procedures, and mobilization and deployment times, are descr bed in ACS *Technical Manual*, Tactic C-14 . The features of the vessels and boom are outlined in Tactic L-6.	C-14 (2)
(vi) Spill Containment and Control Actions	Mechanical on-water response equipment is mobilized on Day 1 at West Dock and Deadhorse. Vessel-based systems comprising containment boom and skimmers recover oil from the water. See Figure 1-7. Containment boom is deployed along the south face of the production island.	
(vii) Spill Recovery Procedures	The capabilities of mechanical oil containment and recovery equipment listed in Table 1-14 meet the response planning standards that involve an unreduced RPS volume. The equipment is further descr bed in ACS *Technical Manual*, Volume 1, Logistics Section, particularly in Tactic L-6. Throughout the first few hours of the spill, the Site Safety Officer determines PPE requirements, establishes a monitoring protocol for personnel protection, and lays out warm and hot access zones. The monitoring protocol establishes safety zones according to Occupational Safety and Health Administration (OSHA) and fire safety standards. Decontamination zones and safety zones are established at West Dock and Northstar. Access to the spill site is carefully controlled and the scene is secured by designated personnel. A vessel provides crew change and supplies to on-water task forces at the end of the first shift, Hour 12.	S-1, S-2, S-3, S-5, L-2 L-12

TABLE 1-13 (CONTINUED): WELL BLOWOUT UNDER TYPICAL SUMMER CONDITIONS RESPONSE STRATEGY

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(vii) Spill Recovery Procedures **(Continued)**	**On-Water Recovery: Task Force 2.** Task Force 2 mobilizes, transits, and deploys in 8 hours. It is comprised of one Bay Boat with two Crucial skimmers and two side boom arms. Two Island Boats tow an open apex containment boom configuration with a 300-foot wide boom sweep positions downwind of the well. One offshore landing craft (Class E Vessel) and one Munson boat (Class D vessel) shuttle four mini-barges and provides crew change support. See Figure 1-7.	R-20C
	On-Water Recovery: Task Force 3. At the beginning of Day 2, Task Force 3 deploys southwest of Northstar. It is comprised of one Bay Boat with two Crucial skimmers and two side boom arms. Two Island Boats tow an open apex containment boom configuration with a 300-foot wide boom sweep positions. One offshore landing craft (Class E Vessel) and one Munson boat (Class D vessel) shuttle four mini-barges and provides crew change support. See Figure 1-7.	R-20C
	On-Water Recovery: Task Force 4. At the beginning of Day 2, Task Force 4 deploys southwest of the island. The Task Force is comprised of one Bay boat with one Crucial skimmer and one side boom arm. As conditions permit, the vessel operates between the barrier islands and the coast. Unified Command also considers hook boom to skimmer tactics for recovery along the shoreline of the barrier islands.	R-32A R-17
	Land-based Fluid Transfer: Task Force 5. Once the laden mini-barges arrive at West Dock, the recovered fluids are offloaded to vacuum trucks. Refer to section (ix) for details of fluid transfer. On Day 9, the wind shifts, and is blowing out of the east. The shoreline protection and on-water recovery task forces shift as necessary. By Day 15, well control is achieved. By Day 18, Task Forces 2 through 5 cease operations.	R-28
	Production Island Liquid Recovery: Task Force 6. On Day 15, a task force arrives at the island by deck barge to remove pools of oil and oiled gravel. Free oil is removed with vacuum trucks.	S-6, S-7 R-6
	Production Island Oiled Gravel Recovery: Task Force 7. Once the liquid oil is removed and the infrastructure is cleaned and/or removed, a bulldozer and backhoe remove oiled gravel. Two front-end loaders each place the gravel into lined, open-ended containers. The containers are transported via deck barge to West Dock.	R-26
(viii) Lightering Procedures	Mini-barges are lightered to vacuum trucks at West Dock.	R-28

TABLE 1-13 (CONTINUED): WELL BLOWOUT UNDER TYPICAL SUMMER CONDITIONS RESPONSE STRATEGY

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(ix) Transfer and Storage of Recovered Oil/Water; Volume Estimating Procedure	The combined liquid transfer capacity of Task Forces 2 through 4 is 6,650 barrels per day (bpd). The transfer rate exceeds the RPS oil volume rate. See Table 1-15. Oil on water subject to recovery is not likely emulsified (S.L. Ross, 2006). Oil recovered from the water and in storage is accompanied by water that is less than 15 percent of the volume of the oil. Free water is decanted from mini-barges with approval from the Unified Command and EPA. Decanted liquids are pumped into recovery booms until oil is observed. Mini-barges can transfer stored liquids from the recovery system at rates greater than the liquids become available. Shuttle boats haul loaded mini-barges to West Dock, 16 nautical miles round trip at 5 knots on average. A shuttling mini-barge can deliver 579 bpd. Four mini-barges have a capacity of 2,316 bpd, greater than the rate at which oily liquid becomes available for storage and transfer.	D-1, R-28
	Land-based Fluid Transfer: Task Force 5. At West Dock, three vacuum trucks operating 20 hours per day have the capacity to offload stored liquid from mini-barges at a rate of 5,040 bpd. See Table 1-15. The trucks haul liquids to Flow Station 1. Recovered fluids in vacuum trucks are manifested accordingly.	D-1, R-28
	From West Dock, oiled gravel removed from the island is hauled by lined end dump trucks to GPB G & I and placed in stockpiles. Gravel volume estimates and measurements of the fraction of oil in gravel yield oil volume estimates.	D-4
(x) Plans, Procedures, and Locations for Temporary Storage and Disposal	The Environmental Unit includes a three-person Waste Management Team to: 1. Fill out and sign manifests, 2. Measure liquid and other waste, and 3. Submit a plan to ADEC for waste management.	
	Vacuum trucks haul recovered liquids to Flow Station 1 for recycling.	D-1
	Non-liquid oily wastes are classified and disposed of as described in the disposal tactics of the ACS *Technical Manual*. Oiled gravel stockpiles are treated under an ADEC-approved long-term plan.	D-2, D-4
	Non-oily wastes are classified and disposed of accordingly.	D-3
(xi) Wildlife Protection Plan	A wildlife protection task force is mobilized on Day 1. The Wildlife Stabilization Center is made available to agency biologists and veterinarians standing by for potential reports of oiled wildlife. Hazing equipment is deployed on shore and on water as conditions allow. Two teams, each with three persons and a Type B vessel, operate at the spill scene. The hazing team deploys noise-making buoys in the oil slick on the first shift.	

TABLE 1-13 (CONTINUED): WELL BLOWOUT UNDER TYPICAL SUMMER CONDITIONS RESPONSE STRATEGY

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(xi) Wildlife Protection Plan **(Continued)**	Oiled animals are captured, stabilized and treated by specialists using ACS equipment, including the wildlife stabilization facility at Prudhoe Bay. Animals requiring further treatment are transported to the Alaska Wildlife Rehabilitation Center in Anchorage. Marine and coastal bird and mammal populations occupying the path of the spilled oil descr bed in the Trajectory section potentially could be affected by oiling. Many of the birds and mammals are important both ecologically and economically. The ACS *Technical Manual*, Volume 2, lists the marine mammal groups and marine bird groups potentially exposed to the scenario's oil and describes their seasonal distribution in the spill vicinity. Threatened and endangered species protection notes are also provided in the *Technical Manual's* map descriptions. In addition, the types of coastal habitats exposed to the oil are listed by level of concern and depicted on maps of the spill area.	W-1 to W-6
	To protect birds and mammals, the main strategy is removing oil from the environment. The primary strategy for direct wildlife protection is hazing and collection of oiled carcasses. Beginning in the early hours of the spill response, hazing is carried out with ACS equipment and trained personnel under the direction and permits of the Alaska Department of Fish and Game (ADFG) and the U.S. Fish & Wildlife Service (USFWS). See ACS *Technical Manual* Tactics W-1 to W-6 for decision-making and field procedures.	
(xii) Shoreline Cleanup Plan	A Shoreline Cleanup Plan is submitted to and approved by Unified Command in the first week. The plan proposes that beaches found oiled by joint industry and agency Shoreline Cleanup Assessment Teams are cleaned to the satisfaction of the regulatory agencies during the summer by teams using the following methods: Manual recovery of heavier pockets of oil, ambient low pressure water deluge, and passive recovery with sorbents. Shoreline assessment is conducted to assess beach impact. Oiled surfaces on Long Island are cleaned up to the satisfaction of ADEC between August 16 and September 30.	SH-1 SH-2 SH-3 SH-5 SH-7

TABLE 1-14: WELL BLOWOUT UNDER TYPICAL SUMMER CONDITIONS OIL RECOVERY CAPACITY

A SPILL RECOVERY TACTIC	B NUMBER OF RECOVERY SYSTEMS	C RECOVERY SYSTEM	D DERATED OIL RECOVERY RATE (YD^3/DAY OR BOPH)	E MOBILIZATION, DEPLOYMENT AND TRANSIT TIME TO SITE[1] (HOURS)	F OPERATING TIME (HOURS IN A 24-HOUR SHIFT)	G DAILY DERATED OIL RECOVERY CAPACITY (YD^3/DAY OR BOPD) (B X D X F)
Task Force 2 R-20C	2	Crucial C Disc 13/30 Skimmer	31[2]	8	20	1,240 bopd
Task Force 3 R-20C	2	Crucial C Disc 13/30 Skimmer	31	24	20	1,240 bopd
Task Force 4 R-32A	1	Crucial C Disc 13/30 Skimmer	31	24	20	620 bopd
Task Force 6 R-6	2	Vacuum Truck	48[3]	Day 15	20	1,920 bopd
Task Force 7 R-26	4	2 Front-end Loader with 4 Dump Trucks	4.9[4]	Day 15	20	392 yd^3/day

[1] The sum of the mobilization, deployment, and transit time is not the fastest time poss ble; rather, it is the time that each specific tactic is first employed in this specific scenario.

[2] Based on the American Society for Testing and Materials' F2709-08 tests, the nameplate recovery rate is 157 boph. Although the skimmer capacity in this scenario is enhanced by containment boom operations, the recovery rate for this scenario is assumed to be 20% of the skimmer's throughput rate (20% x 157 boph = 31 boph).

[3] Vacuum truck recovery calculation: Time = (miles to disposal * 2) / 5 mph + 2(Tc / Sr),
Time = (8 nautical miles from Northstar to West Dock * 2 trips / 5 knots + 10 miles from West Dock to Flow Station 1* 2 trips/35 mph) + 2(300 bbl / 200 boph) = 6.8 hours, where,
Miles to disposal = 8 nautical miles from Northstar to West Dock * 2 trips / 5 knots + 10 miles from West Dock to Flow Station 1 * 2 trips/35 mph
Tc = Vacuum Truck Capacity = 300 bbl
Sr = Suction Rate = 200 boph
Oil recovery rate (ORR) = (vacuum truck capacity/time),
ORR = (300 bbl/6.2 hours) = 48 boph

[4] Dump recovery calculation for gravel: Tc/(Lt+Tt+Ut)=
20 yd^3/[0.25 hour + (8 nautical miles from Northstar to West Dock * 2 trips / 5 knots + 10 miles from West Dock to GPB G & I * 2 trips/35 mph) + 0.08 hour] = 4.9 yd3/hour, where,
T_c = Truck Capacity = 20 yd3
L_t = Load Time = 0.25 hours
T_t = Travel Time = 8 nautical miles from Northstar to West Dock * 2 trips at 5 knots and 10 miles from West Dock to GPB G & I * 2 trips at 35 mph
U_t = Unload Time = 0.08 hours

TABLE 1-15: WELL BLOWOUT UNDER TYPICAL SUMMER CONDITIONS LIQUID HANDLING CAPACITY

A	B	C	D	E	F	G	H	I	J	K
NUMBER OF STORAGE SYSTEMS	**STORAGE CAPACITY DESCRIPTION**	**STORAGE CAPACITY[1] (bbl)**	**TIME TO FILL[2] (hrs)**	**OFFLOADING MECHANISM**	**OFFLOADING RATE[3] (bbl/hr)**	**TRANSIT TIME - BOTH WAYS[4] (hrs)**	**OFF-LOADING TIME (hrs)**	**TOTAL TRANSIT TIME (hrs) =D+G+H**	**HANDLING RATE CAPACITY (boph) =Ax(C/I)**	**HANDLING RATE CAPACITY (bopd) =Jx20**
Task Force 2 – Marine Recovery (2 skimmers)										
4	Mini-barge	237	3.8	R-28	200	3.2	1.2	8.2	11	2,316
Task Force 3 – Marine Recovery (2 skimmers)										
4	Mini-barge	237	3.8	R-28	200	3.2	1.2	8.2	116	2,316
Task Force 4 – Marine Recovery (1 skimmer)										
2	Mini-barge	237	7.7	R-28	200	3.2	1.2	12.1	39	784
Task Force 5 – Land-based Fluid Transfer (West Dock to FS1 via Vacuum Truck)										
3	Vacuum truck	300	1.5	R-28	200	0.6	1.5	3.6	252	5,040

[1] The effective storage capacity of a 249-bbl mini-barge is 237 bbls (ACS Tactic R-28).

[2] The time to fill equals the storage capacity divided by the recovery rate. For the TF-2 and TF-3 mini-barges, the time to fill = 237 bbls / (2 skimmers x 31 boph) = 3.8 hours. The time to fill equals the storage capacity divided by the recovery rate. For the TF-4 mini-barge, the time to fill = 237 bbls / (1 skimmer x 31 boph) = 7.7 hours. For the vacuum truck, the time to fill = 300 bbls / (200 boph) = 1.5 hours.

[3] For the vacuum truck, the offload rate is 200 boph.

[4] The mini-barges travel 16 nautical miles round trip at 5 knots. The transit time is 3.2 hours. Vacuum trucks travel 10 miles each way from West Dock to Flow Station 1 at a speed of 35 mph. The transit time is 0.6 hours.

TABLE 1-16: WELL BLOWOUT UNDER TYPICAL SUMMER CONDITIONS MAJOR OIL CONTAINMENT AND RECOVERY EQUIPMENT EQUIVALENTS

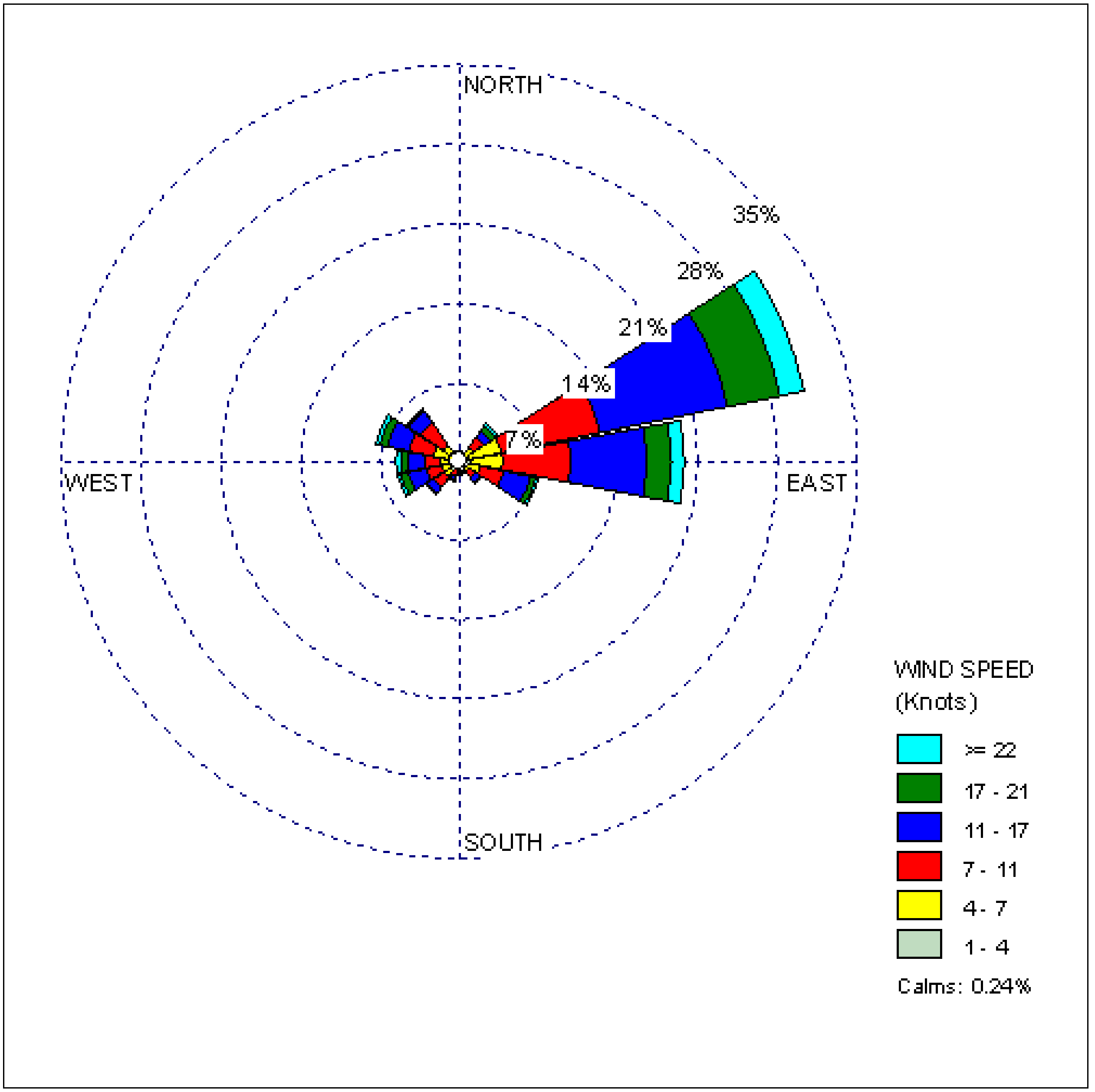
TASK FORCE / TACTIC	QUANTITY
Task Force 1 / C-14	2 Type A Workboat (i.e. *Bullet* and *Snow White*) 2 Airboat 4,000 feet boom
Task Force 2 / R-20C	2 Crucial C Disc 13/30 Skimmer 1 Workboat Type E, Run skimmer and pump; tow mini-barge (i.e. *Agviq*) 2 Island Boats, Tow boom for open apex 1,000 feet boom 1 Workboat Type D, Tow mini-barges (i.e. *Arctic Rose*) 1 Bay Boat, Tow mini-barges, crew change, and logistics 4 Mini-barges (to keep up with maximum recovery rate for 20 hours a day)
Task Force 3 / R-20C	2 Crucial C Disc 13/30 Skimmer 1 Workboat Type E, Run skimmer and pump; tow mini-barge (i.e. *Big Dipper*) 2 Island Boats, Tow boom for open apex 1,000 feet boom 1 Workboat Type D, Tow mini-barges (i.e. *Fireweed*) 1 Bay Boat, Tow mini-barges, crew change, and logistics 4 Mini-barges (to keep up with maximum recovery rate for 20 hours a day)
Task Force 4 / R-32A	1 Crucial C Disc 13/30 Skimmer 1 Bay Boat, Run skimmer and pump; tow mini-barge while loading 2 Workboat Type C, tow mini-barge (or D Class *North Star*) 2 Mini-barges
Task Force 5 / Land-Based Fluid Transfer	3 Vacuum Trucks
Task Force 6 / R-6	2 Vacuum Trucks
Task Force 7 / R-26	1 Bulldozer 1 Backhoe 2 Front-end Loaders 2 x 10 cubic yard open-ended containers (or equivalent)
Wildlife Protection / W-1	2 Workboat Type B
Decontamination of Vessels / S-7	2 Water Truck 2 Steam Cleaning Unit 1 Trash Pump (2-inch) Suction Hose and Discharge Hose (2-inch) Workboat Type B Boom

TABLE 1-17: WELL BLOWOUT UNDER TYPICAL SUMMER CONDITIONS PERSONNEL TO OPERATE OIL CONTAINMENT AND RECOVERY EQUIPMENT

TASK FORCE / TACTIC	LABOR CATEGORY	NO. OF STAFF PER SHIFT DAY 1	NO. OF STAFF PER SHIFT DAYS 2 – 15	NO. OF STAFF PER SHIFT AFTER BLOWOUT ENDS
Task Force 1 / C-14	Small Vessel Operator (also the Team Lead)	4	2	2
	Skilled Technician	6/3*	12	2
Task Force 2 / R-20C	Large Vessel Operator (also the Team Lead)	3	3	3
	Small Vessel Operator	2	2	2
	Skilled Technician	7	7	7
Task Force 3 / R-20C	Large Vessel Operator (also the Team Lead)	0	3	3
	Small Vessel Operator	0	2	2
	Skilled Technician	0	7	7
Task Force 4 / R-32A	Large Vessel Operator (also the Team Lead)	0	2	2
	Small Vessel Operator	0	1	1
	Skilled Technician	0	2	2
Task Force 5 / R-6 (Transfer)	Equipment Operator	3	3	3
	General Technician	3	3	3
Task Force 6 / R-6 (Island Recovery)	Large Vessel Operator (also the Team Lead)	0	0	1
	Equipment Operator	0	0	2
	General Technician	0	0	2
Task Force 7 / R-26 (Island Recovery)	Large Vessel Operator (also the Team Lead)	0	0	1
	Equipment Operator	0	0	4
	General Technician (Spotters)	0	0	2
Wildlife Protection / W-1	Small Vessel Operator (also the Team Lead)	2	2	2
	Skilled Technician	6	6	6
Decontamination of Vessels / S-7	Small Vessel Operator (also the Team Lead)	1	1	1
	Skilled Technician	2/1*	1	1
	General Technician	2	2	2
	Equipment Operator	2	2	2
Staging Area / L-2	Skilled Technician	4	4	4
	General Technician	16	16	16
	Totals:	**63/59**	**83**	**85**

* Asterisk denotes number of staff to set up tactic/number of staff to maintain tactic.

FIGURE 1-5: NORTHSTAR AVERAGE WIND DIRECTION, MAY – OCTOBER



Notes:
Per convention, the wind rose illustrates direction of wind origin (i.e., where the wind is coming from). The wind data were retrieved from the Nearshore Beaufort Sea Meteorological Monitoring and Data Synthesis (Veltkamp and Wilcox, 2007).

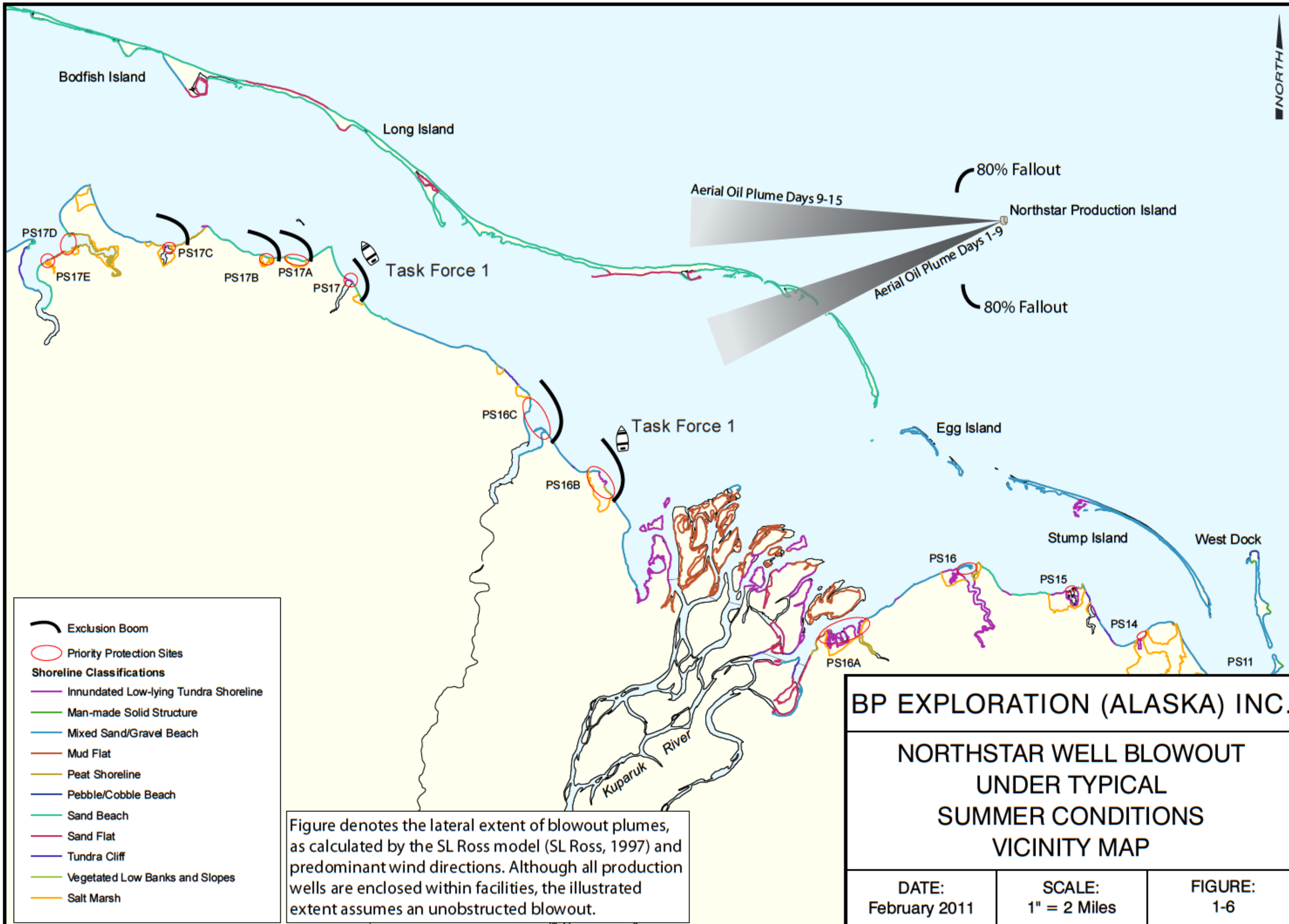


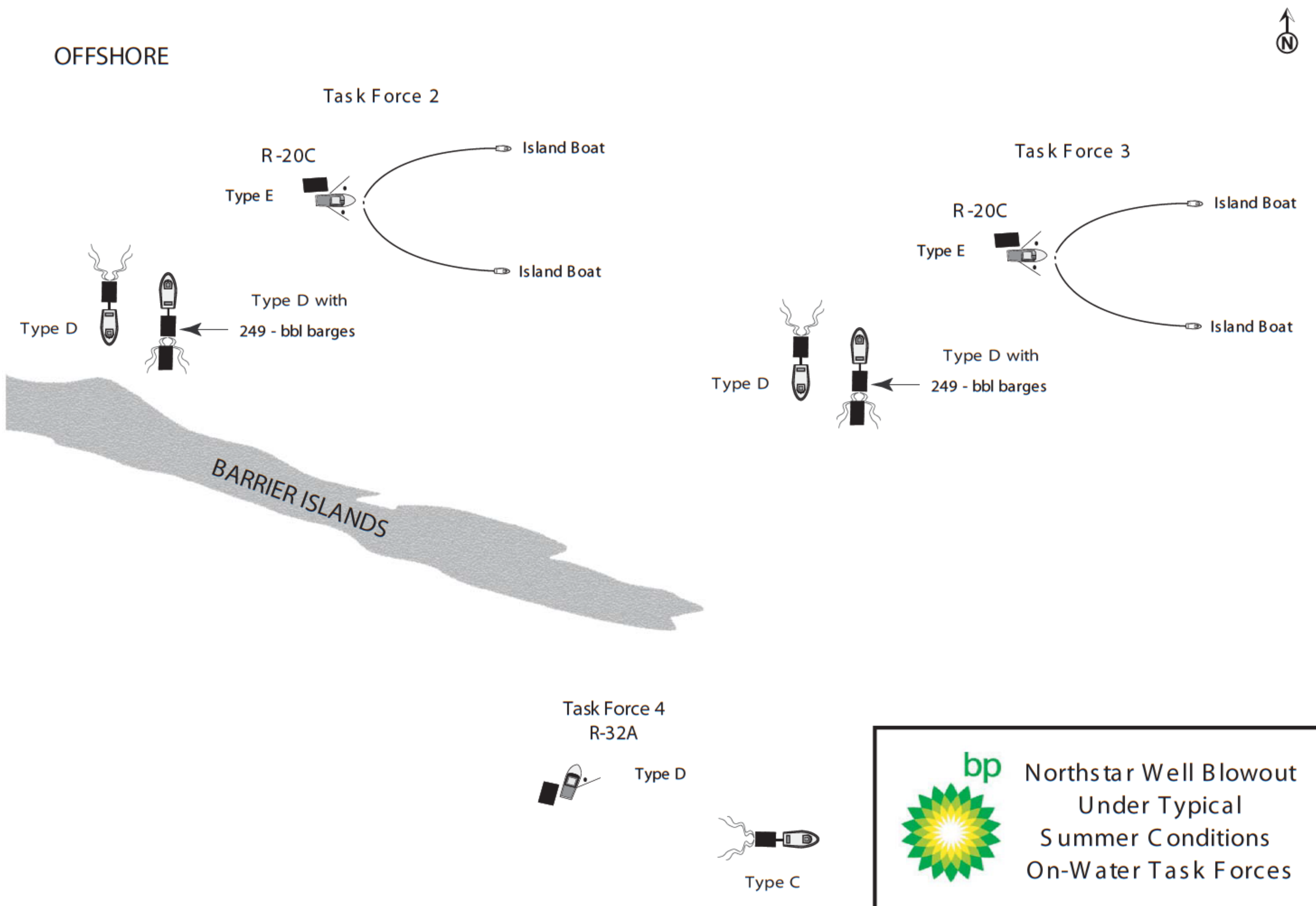
Figure denotes the lateral extent of blowout plumes, as calculated by the SL Ross model (SL Ross, 1997) and predominant wind directions. Although all production wells are enclosed within facilities, the illustrated extent assumes an unobstructed blowout.

BP EXPLORATION (ALASKA) INC.

NORTHSTAR WELL BLOWOUT UNDER TYPICAL SUMMER CONDITIONS VICINITY MAP

DATE:	SCALE:	FIGURE:
February 2011	1" = 2 Miles	1-6

sp16065.mxd



bp

Northstar Well Blowout Under Typical Summer Conditions On-Water Task Forces

Filename: N1-701051707	Not to Scale	Figure: 1-7

THIS PAGE INTENTIONALLY LEFT BLANK

SCENARIO 3

WELL BLOWOUT UNDER TYPICAL WINTER CONDITIONS

THIS PAGE INTENTIONALLY LEFT BLANK

TABLE 1-18: WELL BLOWOUT UNDER TYPICAL WINTER CONDITIONS SCENARIO CONDITIONS

PARAMETER	PARAMETER CONDITIONS
Spill Location	Northstar Production Island, Well NS-30.
Spill Date and Time	January 15, 3:00 pm, 15 days
Cause and Source of Spill	Uncontrolled well blowout through an unobstructed, open orifice
Quantity of Oil Spilled	2,295 barrels of oil per day (bopd) is discharged for 15 days. The total quantity released is 34,425 barrels Northstar crude.
Typical Winter Weather and Visibility	Overcast, -15°F. Unrestricted (See "Oil Spills in Ice Discussion Paper" by Dickins, Vaudrey and SL Ross, 2000, for seasonal air temperatures and visibility discussions.)
Average Wind Speed and Predominant Direction	During winter, the average wind speed is 10 knots. The predominant wind directions were determined as the 16 cardinal compass directions that blow over 10 percent of the time. For November to April, there are five predominant wind directions at Northstar. See Figure 1-8. The wind data were retrieved from the Nearshore Beaufort Sea Meteorological Monitoring and Data Synthesis (Veltkamp, B. and Wilcox, 2007). The weather data presented were collected during the winters of 2000 through 2005.
Surface	Snow depth is 0 to 36 inches, average 12 inches, over ice. Ice is continuous and 6 feet thick. Ice rubble lies within 1,000 feet of the production island. The shear zone, where the moving Arctic ice pack rubbles against the shorefast ice, lies 20 miles north of Seal Island and beyond the reach of the aerial oil. (See "Oil Spills in Ice Discussion Paper," by Dickins, Vaudrey and SL Ross, 2000, pages 2-15 to 2-18 for descriptions of ice at Northstar. Also See Brower et al., 1988, *Climatic Atlas of the Outer Continental Shelf Waters and Coastal Regions of Alaska*, Volume III. National Oceanic & Atmospheric Administration and AEIDC for seasonal shear zone locations.) As typical for the season, the ice road bears wheeled traffic until June 1.
Spill Trajectory	The discharged oil takes the form of an aerial plume extending from the well in the direction of prominent winds (ACS *Technical Manual* Tactic T-6). The S.L. Ross model (1997) indicates that 10 percent of the discharged oil is in the form of drops so small (50 µm or less) that they do not fall to the ground but are held aloft by atmospheric turbulence. For response planning purposes, the oil predicted by the S.L. Ross model to remain airborne is proportionally distributed within the projected blowout plume footprint. The scenario location was selected per ADEC regulations (18 AAC 75,434(e)). Well NS-30 was the highest producing well according to AOGCC's production reports from January 2010 through December 2010. Simulated oil flows from the 4-inch (inner diameter) open orifice well at the rate of 2,295 bopd with gas-to-oil ratio (GOR) of approximately 20,670 standard cubic feet per barrel. These parameters are above the maximum threshold for a 4-inch diameter opening; consequently, the maximum footprint dimensions from the SL Ross model are used. The maximum plume dimensions are 4.9 miles long and 0.7 miles wide. See Figure 1-9. Approximately 13 percent (4,526 bbl) of the oil falls to the Northstar production island. Approximately 80% of the discharged oil falls within 0.7 miles of the well. If left unrecovered for 15 days, the average thickness of the discharged oil deposited between 0.7 and 4.9 miles is 0.003 inches. This sheen would be vis ble as a blue-black sheen on the water surface (ACS *Technical Manual* Tactic T-7.)

TABLE 1-18 (CONTINUED): WELL BLOWOUT UNDER TYPICAL WINTER CONDITIONS SCENARIO CONDITIONS

PARAMETER	PARAMETER CONDITIONS
Spill Trajectory (Continued)	The oil is deposited into 5 plumes over a 15 day period. The volumes deposited are projected to be the following: Days 1 to 2.2 4,950 bbls are deposited to the west. Days 2.3 to 8.1 13,454 bbls are deposited to the west-southwest Days 8.2 to 10.0 4,440 bbls are deposited to the southwest Days 10.1 to 13.1 6,911 bbls are deposited to the east Days 13.2 to 15.0 4,427 bbls are deposited to the east-northeast Oil falling to the island and other surfaces largely stays in place in the snow and gravel. No oil enters open water.

TABLE 1-19: WELL BLOWOUT UNDER TYPICAL WINTER CONDITIONS RESPONSE STRATEGY

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(i) Stopping Discharge at Source	The On-Site Company Representative takes the roll of Initial On-Scene IC, calls the emergency phone number, notifies the Drilling Superintendant, NS Well Operations Team lead, and the affected ADW Team Lead. The IMT is activated. The affected ADW Well Manager calls well control specialists to obtain guidance for source control. Production is shut down, closing in the wells at the surface and subsurface. The Operations Team Lead assumes Surface Control leadership and plans initial surface controls.	A-1, A-2, L-2 BPXA IMS Manual
(ii) Preventing or Controlling Fire Hazards	The Operations Section Chief sets up access zones and routes and firefighting operations to protect assets and workers. Throughout the first few hours of the spill, the Operations Section Chief, with the assistance of the Site Safety Officer and Fire Chief, verify no ignition sources in the area. The Site Safety Officer determines response workers' PPE needs and provides hot and warm zone access information. The first draft of site safety plan (ICS Form 201-5) focuses on the delineation, containment and source control teams. It quickly evolves to include spill recovery teams. Monitoring protocol is established by the Site Safety Officer at work areas for personnel protection. The monitoring protocol establishes safety zones according to applicable Occupational Safety and Health Administration (OSHA) and fire hazard standards. Containment and recovery operations are conducted in accordance with site entry procedures. Recovery operations and oil field operations are disallowed downwind of the blowout well in areas where personnel may become exposed to flash fire hazard or oil particulate matter at concentrations greater than permissible exposure limits. Firewater coverage is set up by source control specialists.	S-1 through S-6
(iv) Surveillance and Tracking of Oil; Forecasting Shoreline Contact Points	The extent of oil on the snow is delineated starting Day 2 so that it can be found if subsequent snowfall or blowing snow covers the spill. Oil is expected to stay in place and not move to shorelines.	T-1
	Aerial surveillance for spilled oil continues through overflood, break-up, and open water seasons.	T-4, T-4A
(v) Environmentally Sensitive Areas and Areas of Public Concern	Based on the ARRT's North Slope Sub-Area Plan, the areas of major concern published in the ACS *Technical Manual* and in the spill trajectory are identified. No priority protection sites lay within the spill trajectories. The presence of ice between the spill and shoreline makes it unlikely that the spilled oil will impact sensitive shoreline resources. The barrier islands are identified as ARRT areas of concern. On Day 1, the Environmental Unit issues an advisory with the concurrence of the State Historic Preservation Officer, and the Operations Chief directs that crews avoid the cultural sites as noted in the ACS *Technical Manual* Map Atlas and Alaska Heritage Resource Survey data. Work is scheduled to minimize response activity disturbance at seal holes under the oversight of National Marine Fisheries Service.	W-6, ACS Map Atlas, Sheets 57-62

TABLE 1-19 (CONTINUED):
WELL BLOWOUT UNDER TYPICAL WINTER CONDITIONS RESPONSE STRATEGY

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(vi) Spill Containment and Control Actions	The capabilities of mechanical oil containment and recovery equipment listed in Table 1-20 meet the response planning standards. The equipment is further descr bed in ACS *Technical Manual*, Volume 1, Logistics Section, particularly in Tactic L-6.	L-2
(vii) Spill Recovery Procedures	A BPXA Field Command Post, decontamination site, and staging area are established at the West Dock Staging Pad. The Unified Command's recovery operations objective is to remove oil from the Northstar Production Island and surrounding sea ice by February 15. Staff and equipment for recovery and transfer of oil in those environments come from in-region spill response resources outlined in *ACS Technical Manual* Tactics L-6, L-8, and L-9.	L-1
	By Day 3, the ice road from West Dock to the island is smoothed with water lifts and supports truck and other wheeled traffic. A four-mile ice road is constructed around the island by Day 12, to assist access by heavy equipment to the oiled areas. Two feet of ice are added to the sea ice to make the ice road. Two crews per shift and two shifts per day build the road at the rate and with the equipment described in ACS *Technical Manual* Tactic C-10.	L-1 L-2
	Rolligons with augers build a 2-acre ice pad with seawater from Days 2-12, thickening the sea ice to 8 feet. The pad then supports a staging area for heavy equipment, decontamination, warm-up and security, but not waste storage. The normal sea ice supports static loads up to 75 tons and moving multiple-loading area equipment that creates resonant waves and weighs up to 90 tons (see Sandwell Engineering, Inc. 2001, "Ice Access Guidelines for Spill Responders." For ACS, Prudhoe Bay, Alaska). Consequently, the equipment with payloads on the ice and listed in Table 3, Tactic L-7, ACS *Technical Manual* can be supported by the untreated ice. For safety, on-ice work is guided by recommendations of an ice specialist.	L-1, L-7, S-6
	Days 1 to 15: **Task Force 1.** Beginning on Day 2, as conditions allow, a task force with earth moving equipment constructs snow berms and digs trenches on or near the island. They divert flowing oil away from the wells and toward low-lying areas where the oil is accessible to vacuum truck hoses.	C-1
	Task Force 2. Vacuum trucks pump accumulated oil from the trenches on the island beginning on Day 2. Loaders and dump trucks recover oiled snow and haul it to interim storage pits at the West Dock Staging Pad beginning on Day 1.	R-6 R-3
	Task Force 3. Beginning on Day 4, a sea ice task force with earth moving equipment constructs berms of snow. At heavier oiled areas, trenches are dug in the sea ice surface to direct oil flow to collection points. At lightly oiled areas, snow fencing is erected on the downwind and upwind sides of the oiled snow to keep the wind from spreading the oil. Two crews each supporting a Ditch Witch and one crew supporting a trimmer make the cuts in two shifts. The objective is to divert surface oil to containment pools.	R-24

TABLE 1-19 (CONTINUED): WELL BLOWOUT UNDER TYPICAL WINTER CONDITIONS RESPONSE STRATEGY

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(vii) Spill Recovery Procedures **(Continued)**	**Task Force 4.** Beginning on Day 4, vacuum trucks recover oil collected in pools near the island, and in trenches with hoses and pumps in series. Heavy equipment recovers lightly oiled snow, and hand shovelers remove oil from hard-to-reach locations in ice rubble. Loaders and dump trucks recover oiled snow and haul it to lined, interim storage pits at the West Dock Staging Pad. The recovery targets for each Task Force are detailed in Table 1-20.	R-6 R-1 R-2
	Days 16 to 30: **Task Force 5.** After the blowout has stopped, earth moving equipment and surface cleaning equipment clean up the Northstar Production Island and its structures. After the surface structures have been cleaned, the oil-contaminated gravel is removed by a trimmer and backhoe. Loaders place gravel in lined dump trucks that haul it to GPB G & I.	R-1 R-2 R-5 R-26
(viii) Lightering Procedures	Not applicable	Not applicable
(ix) Transfer and Storage of Recovered Oil/Water; Volume Estimating Procedure	Vacuum trucks take recovered oil to Flow Station 1 for offloading.	D-1
	Lined end dump trucks transfer oiled snow from the spill site to lined interim storage areas at the West Dock Staging Pad. Estimates of the loads' volumes and oil content are logged by waste specialists in the Environmental Unit.	D-5
	Oiled gravel is hauled in lined end dump trucks and taken to GPB G & I for disposal.	D-4
(x) Plans, Procedures, and Locations for Temporary Storage and Disposal	The Environmental Unit includes a three-person Waste Management Team to: 1. Fill out and sign manifests, 2. Measure liquid and other waste, and 3. Submit a plan to ADEC for waste management.	
	A plan to implement the stockpiling of snow in lined pits and liquid removal is submitted and approved by Unified Command.	D-1, D-5, R-6
	A temporary, lined pit 30 feet by 100 feet composed of timber walls and liner, holding up to 667 cubic yards on the island's concrete mat holds snow recovered by shovelers Days 2 and 3.	D-3

TABLE 1-19 (CONTINUED): WELL BLOWOUT UNDER TYPICAL WINTER CONDITIONS RESPONSE STRATEGY

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(x) Plans, Procedures, and Locations for Temporary Storage and Disposal **(Continued)**	Task Forces deliver contaminated snow to the West Dock Staging Pad for interim storage. There, the snow is stored 12 feet deep in temporary, gravel-bermed, lined pits covering 2.1 acres (1.1 million cubic feet / 12 feet deep / 43,560 ft^2 per acre = 2.1 acres). The oiled snow melts in the spring. Liquids are pumped off with vacuum trucks as they become available and transported to Flow Station 1 for hydrocarbon recycling. The temporary storage pits are continuously monitored until liquids have been processed. Excavated gravel is hauled to GPB G & I. There, the gravel undergoes long-term treatment under a plan approved by ADEC for soil stockpiles. Non-liquid oily wastes are classified and disposed of accordingly. Non-oily wastes are classified and disposed of accordingly.	D-4 D-2
(xi) Wildlife Protection Plan	Polar bear guards, security staff trained by government biologists, are assigned to protect bears and workers. The Wildlife Stabilization Center is made available to agency biologists and veterinarians standing by for potential reports of oiled wildlife. Seal holes are identified with trained dogs beginning Day 2 and activities in their vicinity are restricted. No wildlife becomes oiled. Hazing equipment is deployed as spring approaches.	W-1 W-2
(xii) Shoreline Cleanup Plan	A shoreline cleanup plan is submitted to Unified Command before break-up in case oiled shorelines are discovered after break-up. At break-up, SCAT teams monitor the tundra and adjacent shorelines for oiling according to the plan and find none.	SH-1

TABLE 1-20: WELL BLOWOUT UNDER TYPICAL WINTER CONDITIONS OIL RECOVERY CAPABILITY

A SPILL RECOVERY TACTIC	B NUMBER OF SYSTEMS	C RECOVERY OR TRANSFER SYSTEM	D RECOVERY AND TRANSFER RATE	E MOBILIZATION AND TRANSIT TIME TO SITE (hours)	F OPERATING TIME (hours per day)	G DAILY HANDLING CAPACITY (yd^3 or bopd) B x D x F
R-6, Task Force 2	2	Vacuum Truck	62.5 boph[1]	24	20	2,500 bopd
R-3, Task Force 2	4	Dozer/Front-end Loader with Two Dump Trucks	24 yd^3/hour[2]	24	20	1,920 yd^3
R-24, Task Force 4	2	Vacuum Truck	62.5 boph	24	20	2,500 bopd
	2	4-inch Trash Pump with Suction Hose and Discharge Hose	Transfer by vacuum truck	24	20	Transfer by vacuum truck
R-6, Task Force 4	2	Vacuum Truck	62.5 boph[1]	24	20	2,500 bopd
R-1, Task Force 4	3	Front-end Loader with Dump Truck	24 yd^3/hour[2]	24	20	1,440 yd^3
R-2, Task Force 4	1	Front-end Loader with Dump Truck	24 yd^3/hour[2]	24	20	480 yd^3
R-1, R-26, Task Force 5[3]	4	Front-end Loader with Five Dump Trucks	24 yd^3/hour[2]	24	20	1,920 yd^3
R-2, R-26, Task Force 5[3]	1	Front-end Loader with Dump Truck	24 yd^3/hour[2]	24	20	480 yd^3
R-5, Task Force 5[4]	4	Trimmer/Front-end Loader/Dump Truck	24 yd^3/hour[2]	24	20	1,920 yd^3

[1] Vacuum truck recovery calculation: Time = (miles to disposal * 2) / 35 mph + 2(T_c / S_r),
Time = (14 miles from Northstar to Flow Station 1 * 2 / 35 mph) + 2(300 bbl / 150 boph) = 4.8 hours, where,
Miles to disposal = 14 miles from West Dock to Flow Station 1 * 2 trips at 35 mph
T_c = Vacuum Truck Capacity = 300 bbl
S_r = Suction Rate = 150 boph
Oil recovery rate (ORR) = (vacuum truck capacity/time),
ORR = (300 bbl/4.8 hours) = 62.5 boph

[2] Dump recovery calculation for snow: $T_c/(L_t+T_t+U_t)$ = 20 yd^3/[0.17 hour + (10 miles from Northstar to West Dock Staging Pad x 2 trips/35 mph) + 0.08 hour] = 24 yd^3/hour, where,
T_c = Truck Capacity L_t = Load Time
T_t = Travel Time U_t = Unload Time

[3] Front-end loaders and dump trucks in use for Tactics R-1 and R-2 under Task Force 13 are used to load excavated gravel into dump trucks and transport to GPB G & I.

[4] Front-end loaders and dump trucks in use for Tactics R-1 and R-2 are used to load trimmed snow into dump trucks and transport to snow stockpiles at West Dock Staging Pad.

TABLE 1-21: WELL BLOWOUT UNDER TYPICAL WINTER CONDITIONS MAJOR OIL CONTAINMENT AND RECOVERY EQUIPMENT EQUIVALENTS

TACTIC	NO. TACTICAL UNITS	TOTAL QUANTITY
C-1, Task Forces 1-3[1]	3	3 Front-end Loaders*
R-6, Task Forces 4-6	2	2 Vacuum Trucks
R-3, Task Forces 4-6	4	4 Dozers 4 Front-end Loaders 8 Dump Trucks
C-1, Task Forces 7-9[2]	3	3 Front-end Loaders
C-11, Task Forces 7-9[2]	3	3 Ditch Witches** 200' Boom
C-12, Task Forces 7-9[2]	3	3 Ditch Witches 3 Backhoes
C-19, Task Forces 7-9	4	10,000' Snow Fencing T –Posts and Wire Ties
R-24, Task Forces 10-12	2	2 Vacuum Trucks 2 Fastanks 2 trash pumps
R-6, Task Forces 10-12	2	2 Vacuum Trucks
R-1, Task Forces 10-12	3	3 Dozers 3 Front-end Loaders 6 Dump Trucks
R-2, Task Forces 10-12	1	1 Front-end Loader 1 Dump Truck 3 Snowmachines
R-1, Task Force 13	4	4 Dozers 4 Front-end Loaders 20 Dump Trucks
R-2, Task Force 13	1	1 Front-end Loader 1 Dump Truck 3 Snowmachines
R-5, Task Force 13	4	4 Trimmers 4 Front-end Loaders 4 Dump Trucks
R-26, Task Force 13	1	1 Front-end Loaders 1 Dump Trucks

[1] Front-end loaders used in C-1 for Task Force 1 are also used in C-1 for Task Force 3.

[2] Ditch Witches used in C-11 are also used in C-12.

TABLE 1-22: WELL BLOWOUT UNDER TYPICAL WINTER CONDITIONS PERSONNEL TO OPERATE OIL CONTAINMENT AND RECOVERY EQUIPMENT

LABOR CATEGORY	TACTIC	NO. TACTICAL UNITS	NO. STAFF PER UNIT	NO. STAFF PER SHIFT DAYS 1 - 4	NO. STAFF PER SHIFT DAYS 5 - 8	NO. STAFF PER SHIFT DAYS 9 - 12	NO. STAFF PER SHIFT DAYS 13 - 15	NO. STAFF PER SHIFT DAYS 16 - 30
Team Lead	C-11, Task Force 3	3	1	1	1	1	1	0
	C-12, Task Force 3[1]	3	1	0	0	0	0	0
	C-19, Task Force 3	4	1	1	1	1	1	0
	R-24, Task Force 4[2]	2	1	2	2	2	2	0
	R-2, Task Force 4	1	1	1	1	1	1	0
	R-2 Task Force 5	1	1	0	0	0	0	1
Equipment Operator	C-1, Task Force 1	3	1	3	3	3	3	0
	R-6, Task Force 2	2	2	4	4	4	4	0
	R-3, Task Force 2	4	4	16	16	16	16	0
	C-1, Task Force 3[3]	3	1	0	0	0	0	0
	C-12, Task Force 3	3	1	3	3	3	3	0
	R-24, Task Force 4	2	1	2	2	2	2	0
	R-6, Task Force 4	2	2	4	4	4	4	0
	R-1, Task Force 4	3	4	12	12	12	12	0
	R-2, Task Force 4	1	2	2	2	2	2	0
	R-1, Task Force 5	4	7	0	0	0	0	28
	R-2, Task Force 5[4]	1	2	0	0	0	0	0
	R-5, Task Force 5[4]	4	3	0	0	0	0	0
	R-26, Task Force 5[4]	1	3	0	0	0	0	0

TABLE 1-22 (CONTINUED): WELL BLOWOUT UNDER TYPICAL WINTER CONDITIONS PERSONNEL TO OPERATE OIL CONTAINMENT AND RECOVERY EQUIPMENT

LABOR CATEGORY	TACTIC	NO. TACTICAL UNITS	NO. STAFF PER UNIT	NO. STAFF PER SHIFT DAYS 1 - 4	NO. STAFF PER SHIFT DAYS 5 - 8	NO. STAFF PER SHIFT DAYS 9 - 12	NO. STAFF PER SHIFT DAYS 13 - 15	NO. STAFF PER SHIFT DAYS 16 - 30
General Technician	C-11 Task Force 3	3	1	3	3	3	3	0
	C-12, Task Force 3[1]	3	1	0	0	0	0	0
	C-19, Task Force 3	4	6	6	6	6	6	0
	R-24, Task Force 4[5]	2	10/5	10/5	10/5	10/5	10/5	0
	R-2, Task Force 4	3	9	27	27	27	27	0
	R-2, Task Force 5	3	9	0	0	0	0	27
Total	-	-	-	97/92	97/92	97/92	97/92	56

1 Team Leads and General Technicians used for C-11 are also used in C-12.

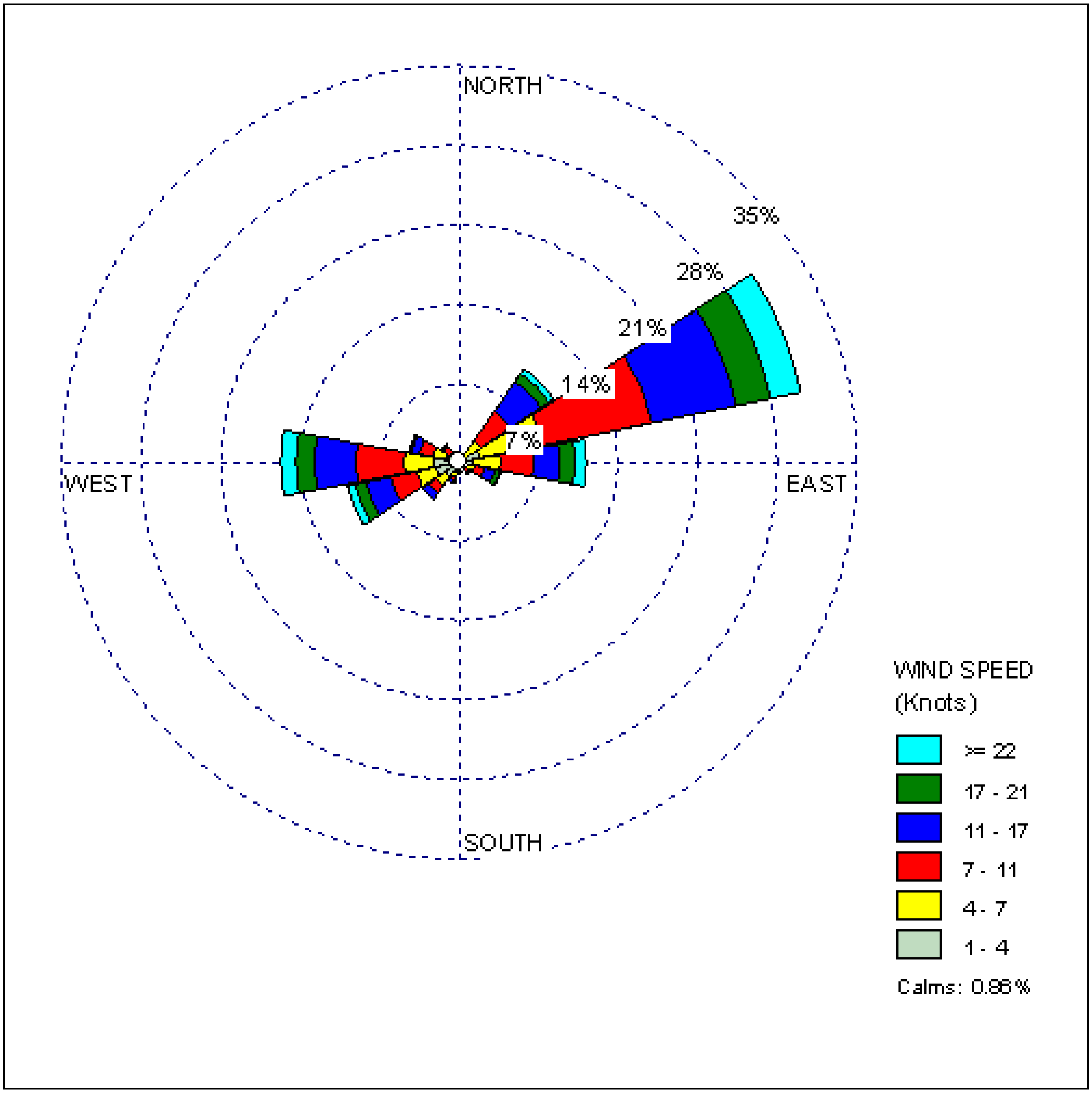
2 One Team Leader supervises four tactical units.

3 Equipment operators used for C-1 in Task Force 1 are also used in C-1 in Task Force 3.

4 Equipment operators for dozers, front-end loaders and dump trucks in used in Task Forces 1-4 are used in Task Force 5.

5 Number of set up staff on Shift 1, followed by maintenance and operations staff on Shift 2 through Day 15.

FIGURE 1-8: NORTHSTAR AVERAGE WIND DIRECTION, NOVEMBER – APRIL



Notes:
Per convention, the wind rose illustrates direction of wind origin (i.e., where the wind is coming from). The wind data were retrieved from the Nearshore Beaufort Sea Meteorological Monitoring and Data Synthesis (Veltkamp and Wilcox, 2007).

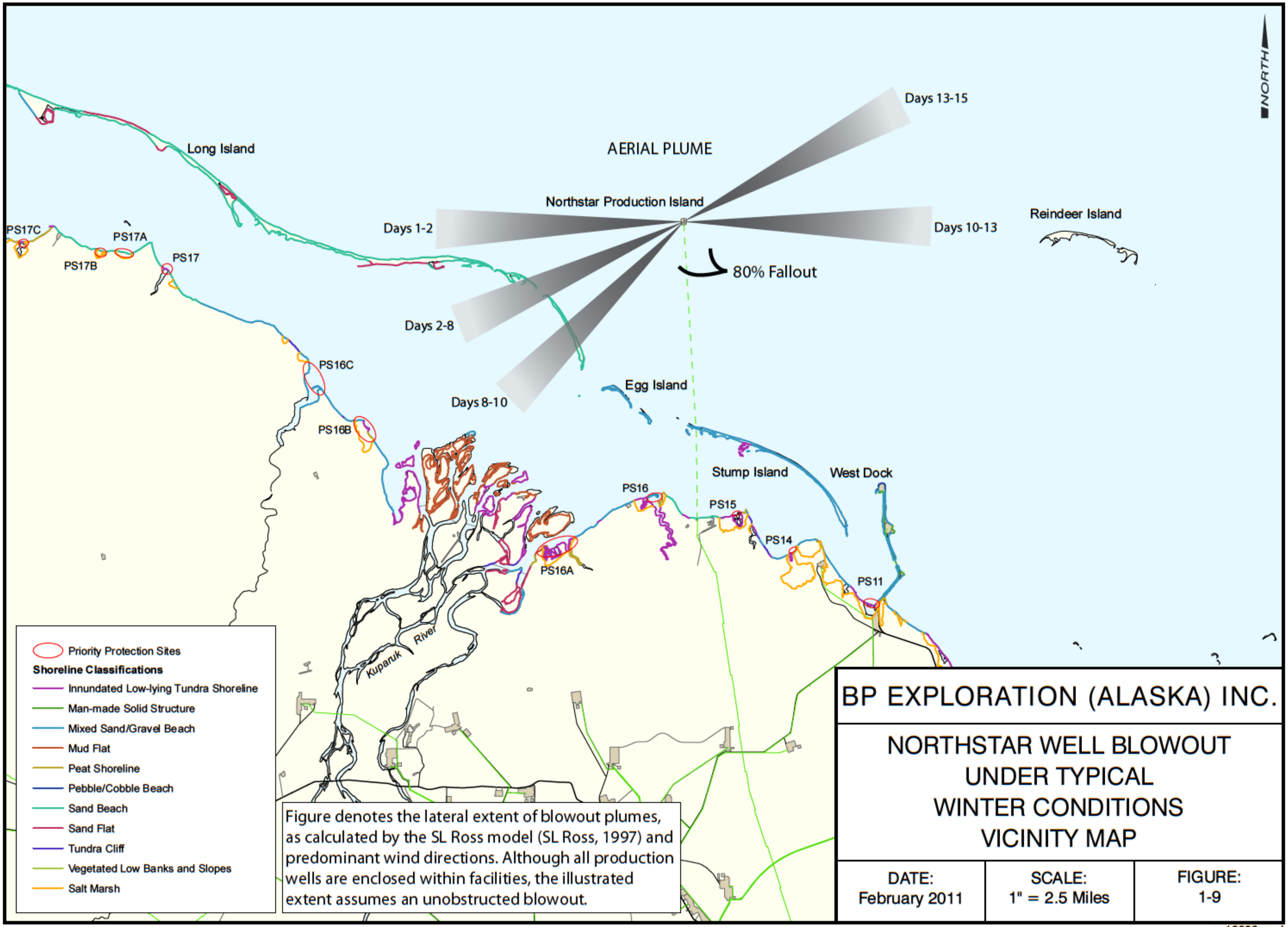


Figure denotes the lateral extent of blowout plumes, as calculated by the SL Ross model (SL Ross, 1997) and predominant wind directions. Although all production wells are enclosed within facilities, the illustrated extent assumes an unobstructed blowout.

BP EXPLORATION (ALASKA) INC.

NORTHSTAR WELL BLOWOUT UNDER TYPICAL WINTER CONDITIONS VICINITY MAP

DATE:	SCALE:	FIGURE:
February 2011	1" = 2.5 Miles	1-9

sp16066.mxd

SCENARIO 4

CRUDE OIL TRANSMISSION PIPELINE RELEASE

THIS PAGE INTENTIONALLY LEFT BLANK

TABLE 1-23: CRUDE OIL TRANSMISSION PIPELINE RELEASE SCENARIO CONDITIONS

INITIAL CONDITIONS	
Spill Location	Northstar crude oil transmission pipeline. Approximately 5,000 feet south of shoreline automatic valve. See Figure 1-10.
Spill Date and Time	August 1, 3:00 pm.
Cause and Source of Spill	Catastrophic pipeline rupture.
Quantity of Spill	4,446 barrels
Weather	45 F, overcast with isolated showers.
Wind Speed and Direction	Less than 10 knots from the east-northeast.
Spill Trajectory	Assuming the crude is absorbed by the tundra at approximately 3 gallons per square foot, the crude oil moves across the surrounding tundra, affecting an estimated 62,244 square feet. The affected area is circular in shape, with a radius of approximately 145 feet.

TABLE 1-24: CRUDE OIL TRANSMISSION PIPELINE RELEASE RESPONSE STRATEGY

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(i) Stopping Discharge at Source	The Control Room Operator reports the alarm to the Communications Operator and closes the shutdown valves. The source is controlled by shut-in of operations and temporary repairs to the line. Notification procedures begin, along with SRT mobilization.	A-1, A-2, L-2 Section 1.2, Reporting and Notification
(ii) Preventing or Controlling Fire Hazards	The Site Safety Officer provides access zone information and determines PPE requirements. The first draft of site safety plan (ICS Form 201-5) focuses on the delineation, containment and source control teams. It quickly evolves to include spill recovery teams. Containment and recovery operations are conducted in accordance with site entry procedures.	S-1 through S-6
(iv) Surveillance and Tracking of Oil; Forecasting Shoreline Contact Points	The control room operator assesses the situation and dispatches Security to perform aerial surveillance of the pipeline. Once safety zones and a decontamination unit have been set up, the oiled area is delineated. An aircraft is dispatched to perform aerial surveillance of the spill and monitor for oil in open water. Location information is digitized and transferred to IMT and Operations Section Chief for response planning and trajectory modeling. Field data are used to periodically update the trajectory map.	T-1 T-2 T-4
(v) Environmentally Sensitive Areas and Areas of Public Concern	No environmentally sensitive areas or areas of public concern are identified.	Map Atlas Sheet 62
(vi) Spill Containment and Control Actions	A primary staging area, complete with decontamination facilities, is established at West Dock on Day 1. **Task Force 1.** On Day 1 a Shoreline Protection Task Force deploys exclusion boom at two lakes near the spill site. They also place a Fastank under the pipeline's leak source. **Task Force 2.** On Day 1, the SRT places shoreseal boom around the perimeter of the spill to contain the contaminated area.	L-2, S-6 C-5 C-4
(vii) Spill Recovery Procedures	**Task Force 3.** Task Force 3 sets up hoses and pumps in series on the first shift. Pumps pump oil from tundra depressions to Fastanks. Oil is transferred from Fastanks to Rolligons with 10,000 gallon tanks on trailers for delivery to West Dock Staging Area to vacuum trucks.	R-24, R-23
	Rope mop skimmers are employed to skim oil from shallow pools not otherwise collected by pumping on Day 2.	R-8 B-2
	Contaminated vegetation is burned to clean up oil left on tundra vegetation. The pipeline and vertical support members are washed.	R-21
(viii) Lightering Procedures	Not applicable	Not applicable.

TABLE 1-24 (CONTINUED): CRUDE OIL TRANSMISSION PIPELINE RELEASE RESPONSE STRATEGY

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(ix) Transfer and Storage of Recovered Oil/Water; Volume Estimating Procedure	Rolligons transfer fluids to vacuum trucks at West Dock Staging Pad. Vacuum trucks take recovered fluids to Flow Station 1 for hydrocarbon recycling. The volumes of stored fluids are gauged with ullage tape and Coliwasa tubes in the tanks and recorded on waste manifests.	R-28
(x) Plans, Procedures, and Locations for Temporary Storage and Disposal	The Environmental Unit includes a three-person Waste Management Team to: 1. Fill out and sign manifests, 2. Measure liquid and other waste, and 3. Submit a plan to ADEC for waste management.	D-1
	The Waste Management Team tallies the quantities and types of waste at the interim storage site at West Dock. Solid and liquid waste from DOT pipelines are disposed of in accordance with the “Alaska Waste Disposal and Reuse Guide” and consultation with the Environmental Advisor.	D-2, D-3
(xi) Wildlife Protection Plan	Wildlife monitoring and deterrents to protect animals are put in place at the spill scene during containment and recovery operations. International Bird Research and Rescue is put on stand-by in the event the wildlife treatment facility is required. A wildlife stabilization and treatment center is made operational and available to agency biologists and veterinarians standing by to respond to potential reports of oiled wildlife. No oiled wildlife is encountered. An aircraft monitors wildlife twice daily at the spill scene.	W-1 through W-6
(xii) Shoreline Cleanup Plan	Tundra is cleaned over 30 days to the satisfaction of ADEC. An assessment is conducted to understand the nature and extent of oiling. Based on the assessment, priorities for cleanup are established. A monitoring program is established for oiled tundra.	R-9, B-2, SH-1, 7, 10 and 11

TABLE 1-25: CRUDE OIL TRANSMISSION PIPELINE RELEASE OIL RECOVERY CAPABILITY

A SPILL RECOVERY TACTIC	B NUMBER OF SYSTEMS	C RECOVERY SYSTEM	D DERATED OIL RECOVERY RATE (boph)	E MOBILIZATION, DEPLOYMENT AND TRANSIT TIME TO SITE (hours)	F OPERATING TIME (hours in a 24-hour shift)	G DAILY DERATED OIL RECOVERY CAPACITY (bopd) B x D x F
R-24	2	4" Trash Pump with 4" Suction and Discharge Hoses	1,071[1]	12	20	42,840
R-23	2	Rolligon with 10,000 Gallon Tank on Trailer	33[2] (Transfer)	12	20	1,320 (Transfer)
	2	4" Trash Pump with 4" Suction and Discharges Hoses	1,071[1]	12	20	42,840
R-8	3	Rope Mop Skimmer	3[3]	12	20	180
B-2	6	Weed Burner	Not applicable	12	20	Not applicable

[1] Trash pump pumping capacity of 750 gpm / 42 gallons x 60 minutes = 1,071 boph. See Tactic L-6.

[2] The 10,000-gallon tank is loaded with a 4-inch trash pump. The rolligon travels West Dock Staging Area to offload to vacuum truck. The vacuum truck transfers recovered fluids to Flow Station 1 for recycling. See Tactic R-23.

[3] Rope mop skimmers' nameplate capacity is 14 boph x 20% derated capacity = 3 boph.

TABLE 1-26: CRUDE OIL TRANSMISSION PIPELINE RELEASE MAJOR OIL CONTAINMENT AND RECOVERY EQUIPMENT EQUIVALENTS

TACTIC	NO. TACTICAL UNITS	TOTAL
C-5	1	1,500 feet
C-4	1	1,500 feet
R-24	2	2, 4" Trash Pumps Suction Hose Discharge Hose 4 Fastanks
R-23	2	2 Rolligons 2, 10,000-Gallon Tanks 2, 4" Trash Pumps Suction Hose Discharge Hose
R-8	3	3 Rope Mop Skimmer, 2-3E
B-2	6	6 Weed Burners with Propane Tank 6 Rakes 6 Fire Extinguishers

TABLE 1-27: CRUDE OIL TRANSMISSION PIPELINE RELEASE PERSONNEL TO OPERATE OIL CONTAINMENT AND RECOVERY EQUIPMENT

LABOR CATEGORY	TACTIC	NO. STAFF PER TACTICAL UNIT	NO. TACTICAL UNITS	DAY 1, NO. OF STAFF PER SHIFT	DAYS 2 - 30, NO. OF STAFF PER SHIFT
Team Leader	C-5	1	1	1	1
	C-4	1	1	1	0
	R-23/R-24	1	2	1	1
General Technician	C-5	3	1	3	3
	C-4	4	4	4	0
	R-24	12/6	2	12	6
	R-23	2	2	4	4
Equipment Operator	R-23	1	2	2	2
Skilled Technicians	R-8	2	3	0	6/3[1]
	B-2	1	6	0	5
Total	-	-	-	28	28/25

[1] Quantity represents number of personnel necessary to set up equipment/personnel necessary to maintain equipment.

(b) (7)(F), (b) (3)

[redacted]

(b) (7)(F), (b) (3)

[redacted]

BP EXPLORATION (ALASKA) INC.

NORTHSTAR CRUDE OIL
TRANSMISSION PIPELINE RELEASE
VICINITY MAP

DATE:	SCALE:	FIGURE:
February 2011	1" = 6000'	1-10

pe13568_11.mxd

THIS PAGE INTENTIONALLY LEFT BLANK

RESPONSE STRATEGY 1

WELL BLOWOUT DURING TYPICAL SPRING CONDITIONS

THIS PAGE INTENTIONALLY LEFT BLANK

RESPONSE STRATEGY PARAMETERS

The following response description is not an ADEC-required response planning standard scenario. Rather, it is an ADEC-required response strategy to account for variations in receiving environments and seasonal conditions according to 18 AAC 75.425(e)(1)(F).

The simulated blowout begins on June 21. At that time, Northstar and the east side of the West Dock causeway are surrounded by sea ice but the west side of the West Dock causeway is open water. Well control is achieved by well capping methods on Day 15 (July 5). By that time, breakup has begun at Northstar and the east side of the West Dock causeway. By July 26, the entire area is ice free. The response begins on Day 1, before spring break up, and continues throughout break up to open water conditions.

The following response description is for illustration only. It is not a performance standard or a guarantee of performance. Some details are examples. Although some equipment is named, it may be replaced by functionally similar equipment. The response timelines are for illustration only. They do not limit the discretion of the persons in charge of the spill response to select any sequence or take whatever time they deem necessary for an effective response without jeopardizing safety.

Actual responses are determined by the Unified Command, and depend on safety considerations, weather, and other environmental conditions, agency permits, response priorities, and other factors. In any incident, consideration for personnel safety is the highest priority. The response description assumes the agency on-scene coordinators and other agency officials immediately grant permits.

Larger responses than illustrated in this response description can be mounted with additional in-region resources and with the mobilization of out-of-region resources.

TABLE 1-28: WELL BLOWOUT UNDER TYPICAL SPRING CONDITIONS RESPONSE STRATEGY

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(i) Stopping Discharge at Source	The On-Site Company Representative takes the role of Initial On-Scene IC, calls the emergency phone number, notifies the Drilling Superintendent, NS Well Operations Team lead, and the affected ADW Team Lead. The IMT is activated. The affected ADW Well Manager calls well control specialists to obtain guidance for source control. Production is shut down, closing in the wells at the surface and subsurface. The Operations Team Lead assumes Surface Control leadership and plans initial surface controls.	A-1, A-2, L-2 BPXA IMS Manual

TABLE 1-28 (CONTINUED)
WELL BLOWOUT UNDER TYPICAL SPRING CONDITIONS RESPONSE STRATEGY

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(ii) Preventing or Controlling Fire Hazards	The Operations Section Chief sets up access zones and routes and firefighting operations to protect assets and workers. Throughout the first few hours of the spill, the Operations Section Chief, with the assistance of the Site Safety Officer and Fire Chief, verify no ignition sources in the area. The Site Safety Officer determines response workers' PPE needs and provides hot and warm zone access information. The first draft of site safety plan (ICS Form 201-5) focuses on the delineation, containment and source control teams. It quickly evolves to include spill recovery teams. Monitoring protocol is established by the Site Safety Officer at work areas for personnel protection. The monitoring protocol establishes safety zones according to applicable Occupational Safety and Health Administration (OSHA) and fire hazard standards. Containment and recovery operations are conducted in accordance with site entry procedures. Recovery operations and oil field operations are disallowed downwind of the blowout well in areas where personnel may become exposed to flash fire hazard or oil particulate matter at concentrations greater than permissible exposure limits. Firewater coverage is set up by source control specialists.	S-1 through S-6
	The IMT submits an ARRT in situ burning application and associated safety plan. The Site Safety Officer approves the plan and passes it to the Incident Commander and the Unified Command for approval.	B-1
(iv) Surveillance and Tracking of Oil; Forecasting Shoreline Contact Points	Oil movement is tracked using a combination of visual observation and remote sensing techniques. Oil on snow is marked with survey lathe or satellite ice beacons deployed from a helicopter based in Deadhorse. When access allows, crews look for oil under ice by opening auger holes in select areas of interest. As breakup occurs, the Kuparuk Twin Otter with FLIR records the location of the oil within the ice leads using onboard equipment. Oil location information is transferred to the IMT and Operations Section Chief for response planning and trajectory modeling. Vector addition and trajectory modeling are used to forecast oil and ice movement.	T-1, T-2, T-4 T-5, T-6
(v) Exclusion Procedures; Protection of Sensitive Resources	Potential oil impact sites and priority protection sites are identified with the help of the monitoring, tracking, and forecasting work. Due to the presence of ice between the spill and sensitive resources, Unified Command predicts it is unl kely that the oil will impact these areas. As breakup occurs, sensitive areas are monitored. Once conditions allow, airboats deploy from West Dock and anchor boom in shallow water near priority protection sites down current of the impacted areas. Deflection booming is the primary tactic as oil is not expected at the sites.	Map Atlas Sheets 58-62 C-14
	The Environmental Unit issues an advisory and the Operations Chief directs that response crews avoid cultural sites on Long Island. The Environmental Unit Leader identifies that the barrier islands constitute the Area of Major Concern, listed in the ARRT's North Slope Sub-Area Plan that lies closest to the spill.	W-6

TABLE 1-28 *(CONTINUED)*
WELL BLOWOUT UNDER TYPICAL SPRING CONDITIONS RESPONSE STRATEGY

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(vi) Spill Containment and Control Actions **and** **(vii) Spill Recovery Procedures**	Mobilization of oil containment and removal equipment begins on Day 1. A BPXA Field Command Post, decontamination site, and staging area are established at the West Dock Staging Pad. By the end of Day 1, tracked personnel carriers, tracked Tucker trucks with blades, and other heavy equipment are mobilized from various locations in Prudhoe Bay to the West Dock Staging Pad. Tracked vehicles and airboats provide stable work platforms and access to the ice. An in situ burning team is mobilized in anticipation of Unified Command approval to burn. On Day 2, the Unified Command determines that the ice conditions do not allow the option of hauling oil to shore with wheeled dump trucks and tankers once the oil is collected in pits and snow. Consequently, Unified Command develops a plan to selectively allow trenching and berming activities and to burn the oil in-situ. Equipment operations and workers on foot follow safety guidelines for vehicle load, ice thickness and ice condition, and for walking on deteriorating ice (Sandwell Engineering Inc., 2001). ACS and SRT oil containment and removal crews work in safety zones determined by the Site Safety Officer, following site entry protocols detailed in Tactic S-1 (ACS, 2010).	L-2 to L-6 and L-8 to L-10 S-1
	Beginning on Day 2, as conditions allow, partial trenches or through-ice slots are excavated in the ice surface with a Ditch Witch to encourage oil flow to a collection point. The machine cuts slots at the rate of 100 lineal feet per hour. Snow berms and boom are also used to divert oil to the trenches (Tactics C-11 and C-12).	C-11, C-12
	A deployment team readies Heli-torch units. A helicopter is mobilized through ACS Master Agreements or through an ACS member company and outfitted with a Heli-torch unit. Following Unified Command approval to burn, the helicopter travels to the spill site and burns surface oil by dropping flaming gelled gasoline on the existing trenches and other areas where oil is collecting. The helicopter burns oil as it emerges until the on-water task forces deploy at the spilled oil. Where access allows, residue is collected with hand tools.	B-3 B-6
	On Day 5 (June 25), Unified Command prohibits over-ice travel to Northstar, except by airboat. Helicopter-supported in-situ burning continues.	
	On Day 15 (July 5), well control is achieved. Helicopter-supported in-situ burning continues. Breakup is underway at Northstar and east of the West Dock causeway. There is open water west of the causeway. Vessels are deployed from West Dock and conduct reconnaissance trips to assess access to Northstar and oiled areas.	

TABLE 1-28 *(CONTINUED)*
WELL BLOWOUT UNDER TYPICAL SPRING CONDITIONS RESPONSE STRATEGY

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(vi) Spill Containment and Control Actions **and** **(vii) Spill Recovery Procedures** **(continued)**	As access allows, mechanical recovery from vessels begins. The first recovery tactics involve free skimming. Bay Boats use rope mops and small 'over-the-side' skimmers. As conditions allow, Crucial skimmers and side boom arms are deployed. As the ice continues to recede, Island Boats tow an open apex containment boom configuration in front of the Bay Boats. Offshore landing craft (Class E Vessel) and Munson boats (Class D vessel) shuttle mini-barges and provide crew change support.	R-31, R-32A R-20
	By July 26, the entire area is ice free. Marine-based recovery operations have unrestricted access. A task force arrives at the island by deck barge to remove pools of oil and oiled gravel. Free oil is removed with vacuum trucks. Once the liquid oil is removed and the infrastructure is cleaned and/or removed, a bulldozer and backhoe remove oiled gravel. Two front-end loaders each place the gravel into lined, open-ended containers. The containers are transported via deck barge to West Dock.	R-20 R-6 R-26
(viii) Lightering Procedures	Mini-barges are lightered to vacuum trucks at West Dock.	R-28
(ix) Transfer and Storage of Recovered Oil/Water; Volume Estimating Procedure	A Liquid Transfer Task Force assembles at West Dock.	R-22
	The residue quantity is estimated by volume measurements at West Dock.	B-6
	Mini-barges have the capacity to store the spilled oil plus more in the form of collected water without off-loading.	R-28
	The recovered liquids are off-loaded by vacuum trucks at West Dock. The volumes of stored oil emulsion and free water are gauged with approved methods.	D-1
(x) Plans, Procedures, and Locations for Temporary Storage and Disposal	The Environmental Unit includes a Waste Management Team to: 1. Fill out and sign manifests, 2. Measure liquid and other waste, and 3. Submit a plan to ADEC for waste management. Vacuum trucks haul recovered liquids to Flow Station 1 for recycling. Non-liquid oily wastes are classified and disposed of as described in the disposal tactics of the ACS *Technical Manual*. Oiled gravel stockpiles are treated under an ADEC-approved long-term plan.	 D-1 D-2 D-3 D-4

TABLE 1-28 (CONTINUED)
WELL BLOWOUT UNDER TYPICAL SPRING CONDITIONS RESPONSE STRATEGY

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(xi) Wildlife Protection Plan	Daily overflights beginning Day 1 monitor the spill scene for animals at risk. A wildlife task force is mobilized to exclude mammals from entering oiled areas, monitor the oil trajectory area, recover oiled carcasses, and/or capture oiled wildlife, as necessary. The International Bird Rescue Research Center (IBRRC) is put on standby in the event the wildlife treatment facility should be required. A wildlife stabilization and treatment center is made operational and available to agency biologists and veterinarians standing by to respond to potential reports of oiled wildlife. As breakup conditions continue, teams with three persons and a 29-foot hull class vessel deploys noise-making buoys as bird deterrents.	W-1 W-2B W-3 W-4 W-5
(xii) Shoreline Cleanup Plan	Once conditions allow, shoreline assessment is conducted to assess potential impact to shorelines. A Shoreline Cleanup Plan is submitted to and approved by Unified Command. The plan proposes that beaches found oiled by joint industry and agency Shoreline Cleanup Assessment Teams are cleaned to the satisfaction of the regulatory agencies using the following methods: Manual recovery of heavier pockets of oil, ambient low pressure water deluge, passive recovery with sorbents, and natural recovery.	SH-1 SH-2 SH-3 SH-5 SH-7

PHMSA 000109365

THIS PAGE INTENTIONALLY LEFT BLANK

PHMSA 000109366

RESPONSE STRATEGY 2

CRUDE OIL TRANSMISSION PIPELINE RUPTURE DURING SPRING BREAK-UP

PHMSA 000109367

THIS PAGE INTENTIONALLY LEFT BLANK

RESPONSE STRATEGY PARAMETERS

The following response strategy illustrates procedures and methods that may be taken in response to a hypothetical oil spill from Northstar's sub-sea crude oil transmission pipeline at the beginning of spring break-up. See Figure 1-11 and Figure 1-12.

TABLE 1-29: CRUDE OIL TRANSMISSION PIPELINE RUPTURE DURING SPRING BREAK-UP

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(i) Stopping Discharge at Source	The Control Room Operator reports the alarm to the Communications Operator and closes the shutdown valves. The source is controlled by shut-in of operations and temporary repairs to the line. Notification procedures begin, along with SRT mobilization.	A-1, A-2, L-2 BPXA IMS Manual
(ii) Preventing or Controlling Fire Hazards	The Site Safety Officer characterizes the spill site and distributes a Site Safety Plan. Operations are conducted in accordance with site entry procedures. Monitoring protocol is established by the Site Safety Officer on work vessels to ensure proper personnel protection.	S-1 through S-6
	The IMT submits an ARRT in situ burning application and associated safety plan. The Site Safety Officer approves the plan and passes it to the Incident Commander and the Unified Command for approval.	B-1
(iv) Surveillance and Tracking of Oil; Forecasting Shoreline Contact Points	Oil movement is tracked using a combination of visual observation and remote sensing techniques. Satellite ice beacons are deployed from a helicopter based in Deadhorse. The Kuparuk Twin Otter with FLIR geocodes the location of the oil within the ice leads using onboard equipment. Oil location information is digitized and transferred to the IMT and Operations Section Chief for response planning and trajectory modeling. Vector addition and trajectory modeling are used to forecast oil and ice movement.	T-4A T-4 T-5
(v) Exclusion Procedures; Protection of Sensitive Resources	Potential oil impact sites and priority protection sites are identified with the help of the monitoring, tracking, and forecasting work. Due to the presence of ice between the spill and sensitive resources, Sit Sat predicts it is unlikely that the oil will impact these areas.	Map Atlas Sheets 58-62
	The Environmental Unit issues an advisory and the Operations Chief directs that response crews avoid cultural sites on Long Island. The Environmental Unit Leader identifies that the barrier islands constitute the Area of Major Concern, listed in the ARRT's North Slope Sub-Area Plan that lies closest to the spill.	W-6
(vi) Spill Containment and Control Actions	An in situ burning team is mobilized in anticipation of Unified Command approval to burn. A deployment team readies Heli-torch units. A helicopter is mobilized through ACS Master Agreements or through an ACS member company and outfitted with a Heli-torch unit on the first shift.	B-3
	Vessels and mini-barges mobilize at West Dock on Day 1 and deploy at the spill scene as ice allows (Bronson, 2000).	R-31, Option B

TABLE 1-29 (CONTINUED): CRUDE OIL TRANSMISSION PIPELINE RUPTURE DURING SPRING BREAK-UP

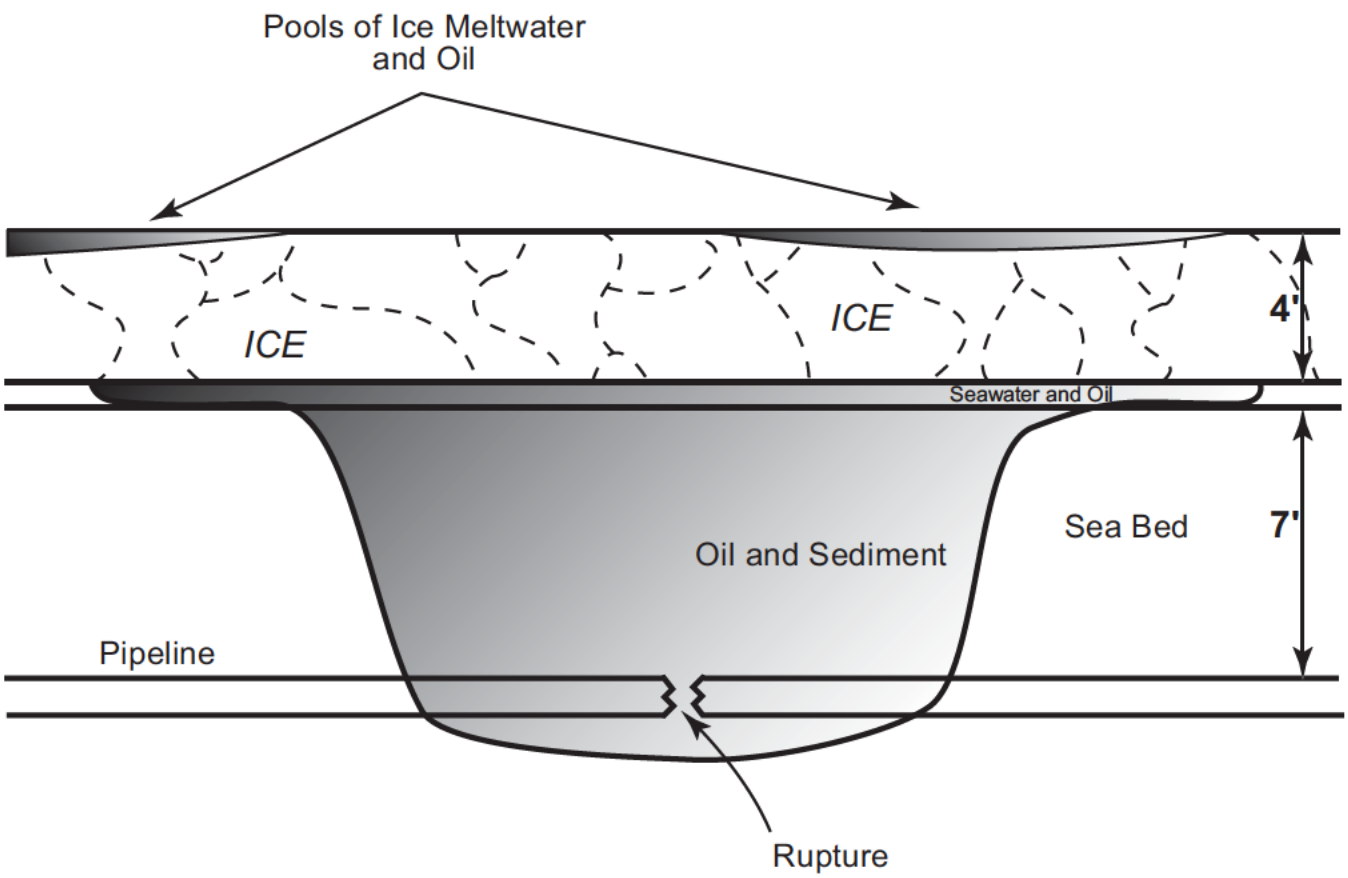
ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(vii) Spill Recovery Procedures	Following Unified Command approval to burn at Hour 6, the helicopter travels to the spill site and burns surface oil by dropping flaming gelled gasoline over the entire oiled area. The helicopter burns oil as it emerges until the on-water task forces deploy at the spilled oil.	B-3
	A primary staging area, complete with decontamination facilities, is established at West Dock on Day 1.	L-2
	In greater ice concentrations, detached configurations free-skim with Crucial C Disc 13/30 skimmers. Oil and water are stored immediately in mini-barges. As regional ice coverage decreases, free-skimming systems convert to boom containment tactics. The boom containment and skimmer configurations follow paths between ice.	R-31, Option B
	An additional Type D offshore workboat not assigned to oil removal or oil transfer tasks carries supplies and replacement crew members to the offshore teams.	R-17
(viii) Lightering Procedures	Not applicable.	
(ix) Transfer and Storage of Recovered Oil/Water; Volume Estimating Procedure	A Liquid Transfer Task Force assembles at West Dock.	R-22
	The residue quantity is estimated by volume measurements at West Dock.	B-6
	Mini-barges have the capacity to store the spilled oil plus more in the form of collected water without off-loading.	R-28
	The recovered liquids are off-loaded by vacuum trucks at West Dock. The volumes of stored oil emulsion and free water are gauged with ullage tape and Coliwasa tubes.	D-1
(x) Plans, Procedures, and Locations for Temporary Storage and Disposal	The Environmental Unit includes a 3-person Waste Management Team to 1. Fill out and sign manifests, 2. Measure liquid and other waste, and 3. Submit a plan to ADEC for waste management. The Waste Management Team tallies the quantities and types of waste at the interim storage site at West Dock. Solid and liquid waste from DOT pipelines are disposed of in accordance with the “Alaska Waste Disposal and Reuse Guide” and consultation with the Environmental Advisor.	 D-1 D-2 D-3

TABLE 1-29 (CONTINUED): CRUDE OIL TRANSMISSION PIPELINE RUPTURE DURING SPRING BREAK-UP

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(xi) Wildlife Protection Plan	Daily overflights beginning Day 1 monitor the spill scene for animals at risk. A helicopter deploys noise-making buoys as bird deterrents in the floating oil as oiled leads appear before Day 3. A wildlife task force excludes birds and mammals from entering oiled areas on water, monitors the oil trajectory area, recovers oiled carcasses and captures oiled wildlife. Teams with three persons and a 29-foot hull class vessel operate at the spill scene beginning on Day 3. International Bird Research and Rescue, Inc. (IBRRC) is put on standby in the event the wildlife treatment facility should be required. A wildlife stabilization and treatment center is made operational and is made available to agency biologists and veterinarians standing by to respond to potential reports of oiled wildlife.	W-1 W-2B W-3 W-4 W-5
(xii) Shoreline Cleanup Plan	Although no shoreline impact is anticipated, development of a Shoreline Cleanup Plan is initiated. Once complete open water arrives, shoreline assessment is conducted to assess beach impact, and beaches found oiled are marked to be cleaned and techniques to be used are determined.	SH-1

(b) (7)(F), (b) (3)

[redacted]



[redacted]

Northstar Crude Oil Transmission Pipeline Rupture During Spring Response Strategy Simulated Oil Distribution

Filename: N1-1601071707	1" = Approx. 5 Feet	Figure: 1-12

THIS PAGE INTENTIONALLY LEFT BLANK

RESPONSE STRATEGY 3

CRUDE OIL TRANSMISSION PIPELINE RUPTURE DURING SUMMER

PHMSA 000109375

THIS PAGE INTENTIONALLY LEFT BLANK

RESPONSE STRATEGY PARAMETERS

The following response strategy illustrates procedures and methods that may be taken in response to a hypothetical oil spill from Northstar's sub-sea crude oil transmission pipeline during summer. See Figure 1-13.

TABLE 1-30: CRUDE OIL TRANSMISSION PIPELINE RUPTURE DURING SUMMER

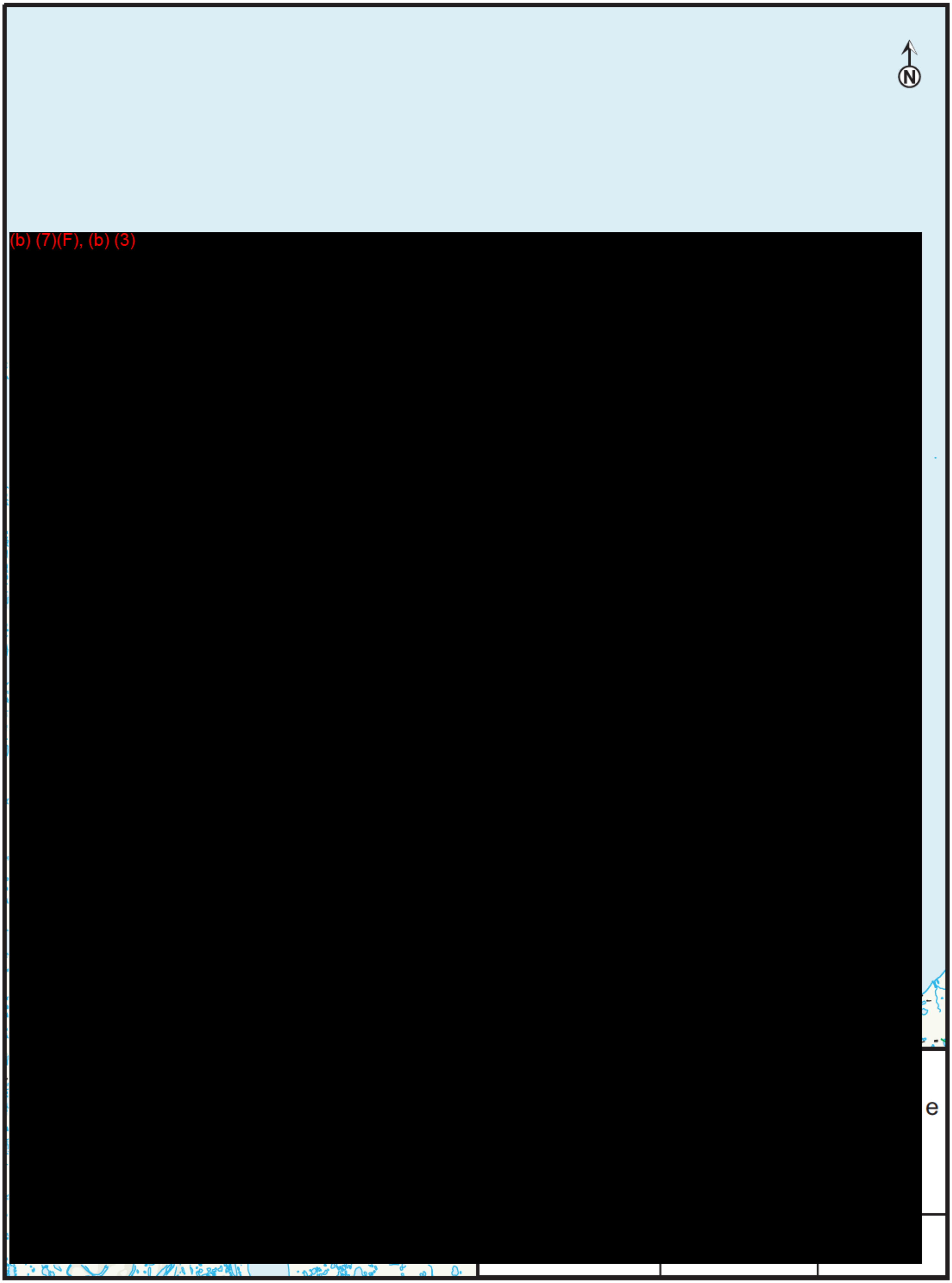
ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(i) Stopping Discharge at Source	The Control Room Operator reports the alarm to the Communications Operator and closes the shutdown valves. The source is controlled by shut-in of operations and temporary repairs to the line. Notification procedures begin, along with SRT mobilization.	A-1, A-2 Section 1.2, Reporting and Notification
(ii) Preventing or Controlling Fire Hazards	The Site Safety Officer characterizes the spill site and distributes a Site Safety Plan. Operations are conducted in accordance with site entry procedures. Monitoring protocol is established by the Site Safety Officer on work vessels to ensure proper personnel protection.	S-1 through S-6
(iv) Surveillance and Tracking of Oil; Forecasting Shoreline Contact Points	Oil movement is tracked using a combination of visual observation and remote sensing techniques. The Kuparuk Twin Otter with FLIR geocodes the location of the oil using onboard equipment. Oil location information is digitized and transferred to the IMT and Operations Section Chief for response planning and trajectory modeling. The lead downwind recovery vessel deploys tracking buoys at Hour 3.	T-4
	Vector addition and trajectory modeling are used to forecast oil and ice movement.	T-5
(v) Exclusion Procedures; Protection of Sensitive Resources	Potential oil impact sites and priority protection sites are identified with the help of monitoring, tracking and forecasting work. The Environmental Unit Leader identifies that the barrier islands constitute the Area of Major Concern, listed in the ARRT's North Slope Sub-Area Plan that lies closest to the spill.	Map Atlas Sheets 58-62
	On Day 1 a Shoreline Protection Task Force deploys exclusion boom at the four PS locations in Gwydyr Bay lagoon. Teams, traveling by small workboats and airboats from West Dock, each place boom in the quantities described and with the boom described in ACS *Technical Manual* Map Atlas Sheet 62.	C-14
	The Environmental Unit issues an advisory and the Operations Chief directs that response crews avoid the cultural sites on the barrier islands and the mainland shore that are noted in the ACS *Technical Manual*.	W-6

TABLE 1-30 (CONTINUED): CRUDE OIL TRANSMISSION PIPELINE RUPTURE DURING SUMMER

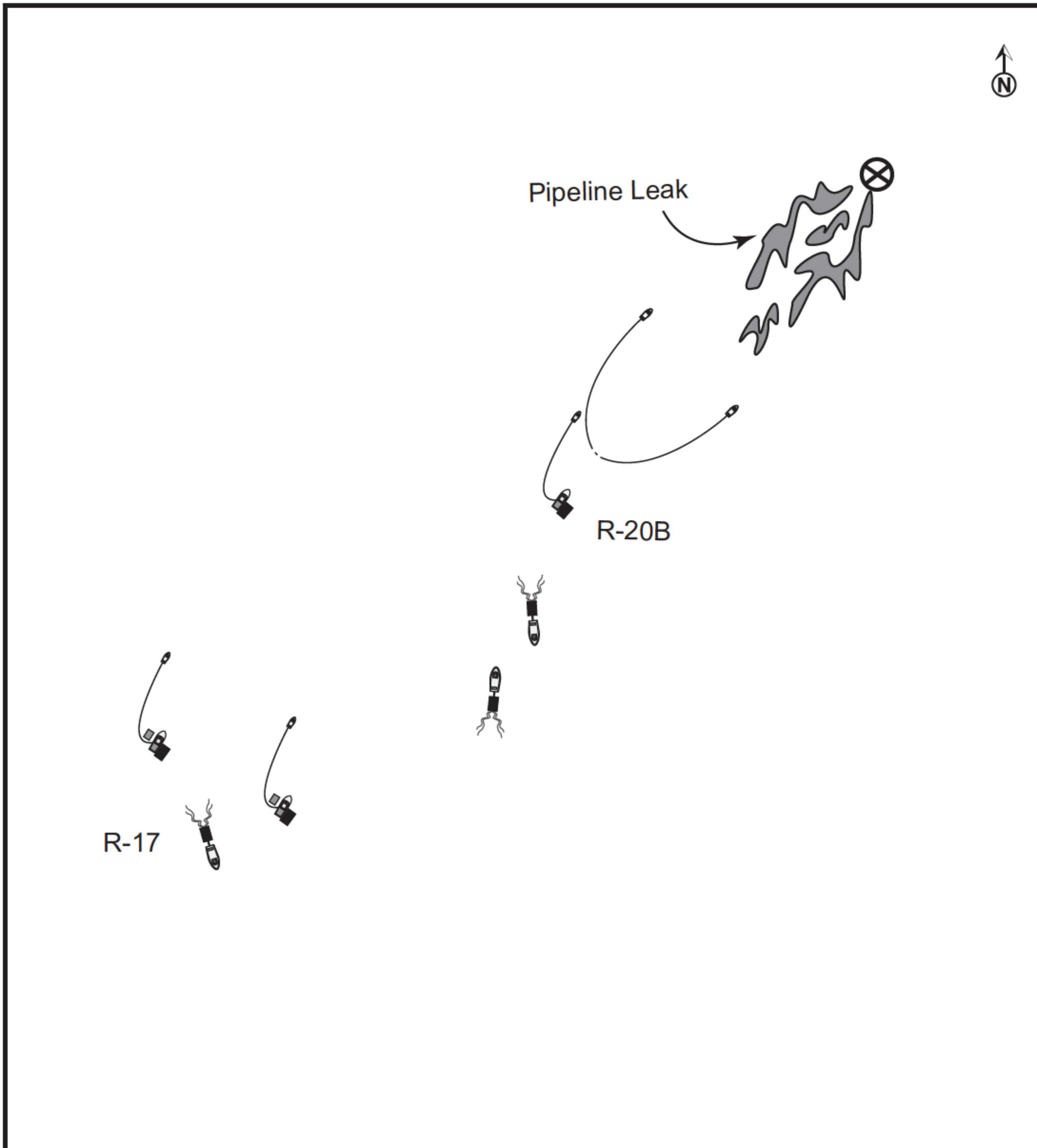
ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(vi) Spill Containment and Control Actions **and** **(vii) Spill Recovery Procedures**	Vessels and mini-barges mobilize at Northstar Island and West Dock and deploy as recovery task forces at the spill scene at Hour 6.	R-20, Option B
	Task Force 1. Its objective is to recover oil as it surfaces and begins to move from the leak site. If the water depth and ocean currents are amendable, the task force deploys boom in a diamond shape, encircling the area where the discharged oil first appears at the ocean surface. If the diamond configuration is not possible, a vessel-based boom-skimmer system deploys directly downwind of the leak. Upon reaching the spill scene, the open apex boom and the following boom-skimmer configuration deploy 4,000 feet from the leak site where the oil swath is 1,000 feet wide. Then the system moves upwind, recovering oil, and positions its open apex boom containment area centrally over the leak site (see Figure 1-14).	R-30 R-17
	Task Force 2. J-boom skimmer teams deploy downwind of Task Force 2 at Hour 6. The objective is to recover the scattered oil that surfaced in the first hours and moved from the leak vicinity (see Figure 1-14). A primary staging area, complete with decontamination facilities, is established at West Dock on Day 1.	L-2, S-6
(viii) Lightering Procedures	Not applicable.	Not applicable
(ix) Transfer and Storage of Recovered Oil/Water; Volume Estimating Procedure	Mini-barges load less than their tank capacity to avoid grounding in the shallow water. A Liquid Transfer Task Force assembles. The stored liquids are off-loaded from mini-barges to vacuum trucks at West Dock. The volumes of stored oil emulsion and free water are gauged with ullage tape and Coliwasa tubes in the barge tanks and recorded on waste manifests.	R-28
(x) Plans, Procedures, and Locations for Temporary Storage and Disposal	The Environmental Unit includes a three-person Waste Management Team to: 1. Fill out and sign manifests, 2. Measure liquid and other waste, and 3. Submit a plan to ADEC for waste management. The Waste Management Team tallies the quantities and types of waste. Solid and liquid waste from DOT pipelines are disposed of in accordance with the "Alaska Waste Disposal and Reuse Guide" and consultation with the Environmental Advisor.	D-1 D-2 D-3

TABLE 1-30 (CONTINUED): CRUDE OIL TRANSMISSION PIPELINE RUPTURE DURING SUMMER

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(xi) Wildlife Protection Plan	Wildlife monitoring and deterrents to protect animals are put in place at the spill scene during recovery operations. Teams with three persons and Type B vessels, operate at the spill scene on Day 1. The hazing team deploys noise-making buoys in the oil slick on the first shift. A wildlife task force excludes birds and mammals from entering oiled areas on water, monitors the oil trajectory area, recovers oiled carcasses and captures oiled wildlife. A wildlife stabilization and treatment center is made operational and is made available to agency biologists and veterinarians standing by to respond to potential reports of oiled wildlife. An aircraft monitors wildlife twice daily at the spill scene.	W-1 W-2, L-6 W-3 W-4 W-5
(xii) Shoreline Cleanup Plan	Shorelines, tundra and gravel areas are cleaned to the satisfaction of ADEC. Monitoring programs are established for these areas.	R-9, R-26, SH-1, SH-2, SH-3, SH-4, SH-5, SH-7, SH-10 and SH-11



[redacted]



[redacted]

Northstar Crude Oil
Transmission Pipeline Rupture
During Summer Response Strategy
Simulated Recovery Tactics

Filename: N1-1801071707	Not to scale	Figure: 1-14

THIS PAGE INTENTIONALLY LEFT BLANK

PHMSA 000109382

RESPONSE STRATEGY 4

CRUDE OIL TRANSMISSION PIPELINE RUPTURE DURING FALL

PHMSA 000109383

THIS PAGE INTENTIONALLY LEFT BLANK

RESPONSE STRATEGY PARAMETERS

The following response strategy illustrates procedures and methods that may be taken in response to a hypothetical oil spill from Northstar's sub-sea crude oil transmission pipeline during fall. See Figure 1-15.

TABLE 1-31: CRUDE OIL TRANSMISSION PIPELINE RUPTURE DURING FALL

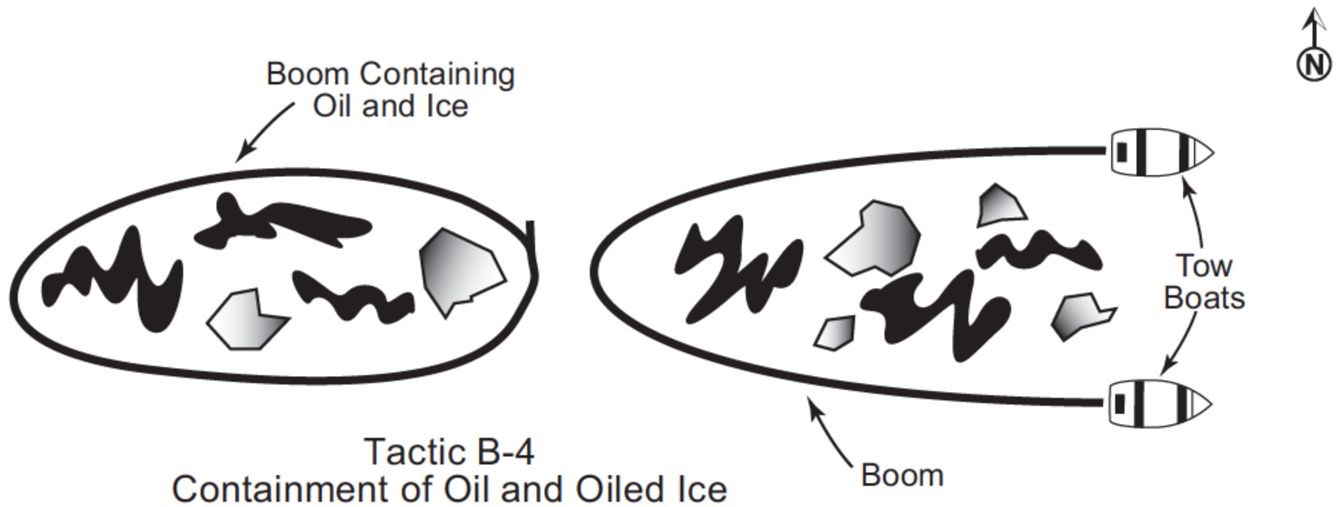
ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(i) Stopping Discharge at Source	The Control Room Operator reports the alarm to the Communications Operator and closes the shutdown valves. The source is controlled by shut-in of operations and temporary repairs to the line. Notification procedures begin, along with SRT mobilization.	A-1, A-2 Section 1.2, Reporting and Notification
(ii) Preventing or Controlling Fire Hazards	The Site Safety Officer characterizes the spill site and distributes a Site Safety Plan. Operations are conducted in accordance with site entry procedures. Monitoring protocol is established by the Site Safety Officer on work vessels to ensure proper personnel protection.	S-1 through S-6
(iv) Surveillance and Tracking of Oil; Forecasting Shoreline Contact Points	Oil movement is tracked using a combination of visual observation and FLIR. The Kuparuk Twin Otter visually tracks the oil. Wind and current vector addition and trajectory modeling are used to forecast oil and ice movement.	T-4, T-5
	On-site observers to coordinate the surveillance program. Site-specific weather forecasts are given to Unified Command. Satellite imagery support services are notified and activated as needed.	
	As the ice consolidates and thickens, crews delineate the oiled areas. Using ice augers, crews drill a pattern of holes in the ice to track oil on the undersurface of the ice. Underwater lights lowered through auger holes to determine the location of oil pockets. Additionally, existing commercial GPR systems can be used from a low-flying helicopter to detect oil trapped under snow on the ice and to detect oil trapped under solid ice (Sørstrøm et al., 2010).	T-3
(v) Environmentally Sensitive Areas and Areas of Public Concern	Potential oil impact sites and priority protection sites are identified with the help of the monitoring and tracking and forecasting work. Projected oil trajectory does not indicate landfall near sensitive sites.	Map Atlas Sheets 58-62
	The Environmental Unit issues an advisory and Operations Chief directs that response crews avoid cultural sites on Long Island. The Environmental Unit Leader identifies that the barrier islands constitute the Area of Major Concern, listed in the ARRT's North Slope Sub-Area Plan that lies closest to the spill.	W-6
(vi) Spill Containment and Control Actions and **(vii) Spill Recovery Procedures**	Workboats with ocean containment boom, fireboom, skimmers, and mini-barges mobilize from West Dock and deploy at the spill scene on the first shift in >1/10 ice coverage. **Team 1 at Initial Oil Slug**. A pair of ACS workboats tows 1,000 feet of boom and deploys the boom. The boom encircles the leading area of oiled ice. Inside the boom, the ice becomes a single mass of slush over several hours as the pieces encounter resistance by the boom.	 R-30

TABLE 1-31 (CONTINUED): CRUDE OIL TRANSMISSION PIPELINE RUPTURE DURING FALL

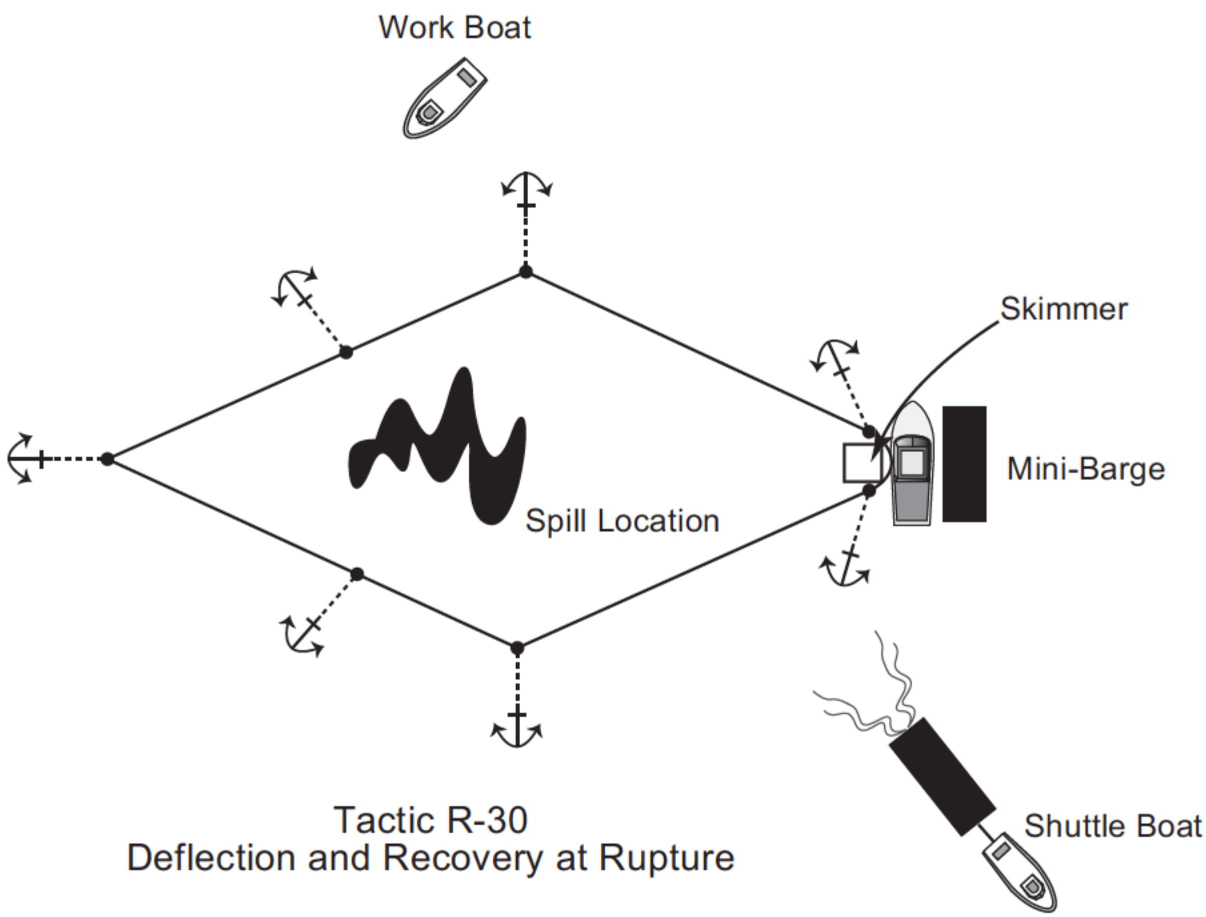
ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(vi) Spill Containment and Control Actions and **(vii) Spill Recovery Procedures** **(Continued)**	**Team 2 at Body of the Oil Slick**. Towing vessels in pairs travel close abeam to avoid collecting ice until they encounter oil. As they encounter the oil, the workboats open the boom sweep to match the swath of the narrow oil slick. When the boom becomes full of ice, the boom ends are connected and released from the tow boats. Each of the two pairs of workboats tows 2,000 feet of boom, to encircle two sections of the oil slick downwind of leak source (See Figure 1-15).	R-30
	Team 3 at Source. A workboat anchors an ice-deflection boom configuration, 100 feet on each side on the first shift. The objectives are to deflect oncoming ice away from the surfacing oil and from a containment-skimming system and to direct oil to the containment system. As a consequence of ice deflection, the skimmer encounters the oil in ice-free water. A primary staging area, complete with on-water and on-land decontamination facilities, is established at West Dock.	R-30
	Aerial and on-water observers report that grease and slush ice predominate in the spill zone at Hour 3. **Team 3 at Leak Site.** Above the leak, oil rising to the surface after Team 3 deploys is targeted for skimmer recovery. A pair of workboats deploys boom to concentrate the oil that exits the chevron deflection boom. The anchored deflection boom area releases no ice into the vessel-based boom. A workboat with a Crucial C Disc 13/30 skimmer, boom arm, and mini-barge is positioned down current and in the apex of the boom. The skimmer vessel's boom arm directs oil into the skimmer until the leak stops. Workboats shuttle mini-barges from the skimming vessels. Operations continue through the night with deck lights illuminating the immediate vicinity of the vessels. Workboats shuttling mini-barges also carry supplies and crew members from West Dock to the on-water teams.	R-30
	Team 4 for Oil Entrapped in Fast Ice. Stationary, stable, consolidated shorefast ice (Condition 4) traps the oil in Teams 1 and 2 booms. In December, ice roads are built to access the scattered oil marked by booms and beacons. Oil marked with boom and beacons is excavated soonest. The scattered oil excavation relies on efforts to find the oil. Trimmers remove the oiled ice by April 1.	R-29
(viii) Lightering Procedures	Not applicable	

TABLE 1-31 (CONTINUED): CRUDE OIL TRANSMISSION PIPELINE RUPTURE DURING FALL

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(ix) Transfer and Storage of Recovered Oil/Water; Volume Estimating Procedure	Team 3 mini-barges shuttle recovered liquids from the skimmer operations to West Dock. The recovered oil is stored by the end of Day 1 when the leak and on-water recovery cease. Mini-barges are off-loaded at West Dock on Day 2 on a non-emergency schedule.	R-28
	Once a disposal method has been determined and approved, a Liquid Transfer Task Force off-loads the mini-barge's stored liquids to vacuum trucks. Recovered fluids in vacuum trucks are manifested accordingly.	R-6
	Oily ice is stockpiled in temporary, lined containment cells at the West Dock staging area. Once a disposal method has been determined and approved, a Liquid Transfer Task Force uses vacuum trucks to transfer the oil-water mixture to an approved disposal facility. Recovered fluids in vacuum trucks are manifested accordingly.	R-6
	Oil separating from the melted ice is gauged on waste manifests.	
(x) Plans, Procedures, and Locations for Temporary Storage and Disposal	The Environmental Unit includes a three-person Waste Management Team to: 1. Fill out and sign manifests, 2. Measure liquid and other waste, and 3. Submit a plan to ADEC for waste management.	 D-1 D-2
	The Waste Management Team tallies the quantities and types of waste at the interim storage site at West Dock. Solid and liquid waste from DOT pipelines are disposed of in accordance with the "Alaska Waste Disposal and Reuse Guide" and consultation with the Environmental Advisor.	
(xi) Wildlife Protection Plan	Wildlife monitoring and deterrents to protect animals and workers are put in place at the spill scene, including the nearby shoreline, during recovery operations. Two teams, each with three persons and one workboat, operate at the spill scene on Days 1 and 2.	W-1 W-2B
	A wildlife stabilization and treatment center is made operational and is made available to agency biologists and veterinarians standing by to respond to potential reports of oiled wildlife.	W-4
	Daily overflights monitor wildlife in the area.	W-5
(xii) Shoreline Cleanup Plan	Although no shoreline impact occurs, development of a Shoreline Cleanup Plan is initiated. Assessment is conducted to assess beach impact. If shorelines are found oiled, they are marked and cleaned.	SH-1



Tactic B-4
Containment of Oil and Oiled Ice



Tactic R-30
Deflection and Recovery at Rupture

[redacted]

Northstar Crude Oil
Transmission Pipeline Rupture
During Fall
Containment of Oil and Oiled Ice and
Deflection and Recovery at Rupture

Filename: N1-1901071707	Not to scale	Figure: 1-15

PHMSA 000109388

RESPONSE STRATEGY 5

CRUDE OIL TRANSMISSION PIPELINE RUPTURE DURING WINTER

PHMSA 000109389

THIS PAGE INTENTIONALLY LEFT BLANK

RESPONSE STRATEGY PARAMETERS

The following response strategy illustrates procedures and methods that may be taken in response to a hypothetical oil spill from Northstar's sub-sea crude oil transmission pipeline during winter. See Figure 1-16.

TABLE 1-32: CRUDE OIL TRANSMISSION PIPELINE RUPTURE DURING WINTER

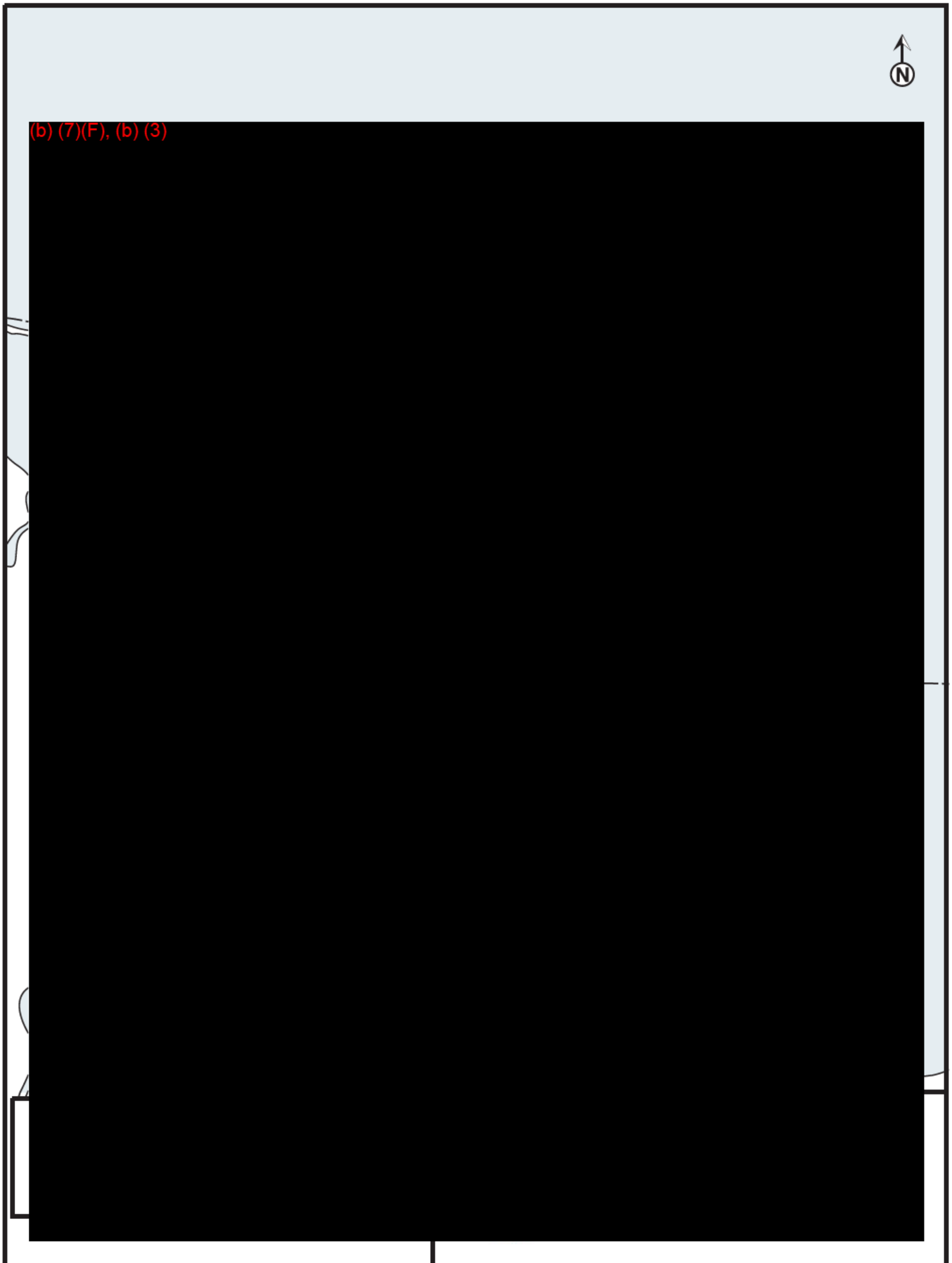
ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(i) Stopping Discharge at Source	The Control Room Operator reports the alarm to the Communications Operator and closes the shutdown valves. The source is controlled by shut-in of operations and temporary repairs to the line. Notification procedures begin, along with SRT mobilization.	A-1, A-2 Section 1.2, Reporting and Notification
(ii) Preventing or Controlling Fire Hazards	The Site Safety Officer characterizes the spill site and distr butes a Site Safety Plan. Operations are conducted in accordance with site entry procedures.	S-1 through S-6, Section 1.1
(iv) Surveillance and Tracking of Oil; Forecasting Shoreline Contact Points	Once safety zones and a decontamination unit have been set up, the oiled area is delineated. A pattern of drill holes in the ice around the discovery hole encounters oil on the undersurface of the ice. Underwater lights lowered to determine the location of oil pockets. Leaked oil is reported trapped on the rough undersurface of the continuous ice over the leak point. Existing commercial GPR systems can be used from a low-flying helicopter to detect oil trapped under snow on the ice and to detect oil trapped under solid ice (Sørstrøm et al., 2010).	T-3
(v) Environmentally Sensitive Areas and Areas of Public Concern	The Environmental Unit issues an advisory and the Operations Chief directs that response crews avoid cultural sites on Long Island. The Environmental Unit identifies that the barrier islands constitute the Area of Major Concern listed in the ARRT's North Slope Sub-Area Plan. Trajectory forecasts predict that the oil will not move with the under ice current to shorelines.	ACS Technical Manual Map Atlas Sheets 60 and 62 W-6
(vi) Spill Containment and Control Actions	Oil becomes trapped in the rough undersurface of the ice, and by ice growth at the periphery of the oiled area and beneath the oil.	Not applicable
(vii) Spill Recovery Procedures	A decision is made to make the recovery of spilled oil the first priority. The objective is removing the oil before July 1. Once containment and recovery of the majority of the oil has been achieved, work will commence on a pipeline repair. Oil remaining trapped in the ice is to be removed in coordination with pipeline repair operations.	
	Ice road and pad construction prepares the site for temporary staging of vehicles and storage tanks. An ice road and an ice pad staging area and decontamination area are built on bottom fast ice as a contingency. The ice road extends 1,000 feet onto floating fast ice to the spill site. Moving and short-term parking loads up to 50 tons (e.g., bulldozer) are supported on the floating shorefast ice at the spill site. Static (long-term) loads up to 25 tons (e.g., loader) are supported as well.	L-1 C-10 L-2, S-6
	The snow is cleared from the ice surface in the contaminated area using a dozer on Day 1.	L-7

TABLE 1-32 (CONTINUED):
CRUDE OIL TRANSMISSION PIPELINE RUPTURE DURING WINTER

ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(vii) Spill Recovery Procedures **(Continued)**	**Recovery with Sumps.** Recovery teams are mobilized to the site on Day 2. Teams construct a series of recovery sumps throughout the contaminated area with Rube Witches and Ditch Witches; each sump is approximately 10 feet on a side and 1.5 feet deep. Three to five holes within each sump allow effective recovery of the trapped oil in the vicinity of the sump (Dickins, D. F., 1997). Recovery sumps are cut throughout the contaminated area. See Figure 1-17. Based on recovery tests in Prudhoe Bay, the estimated recovery efficiency is 95 percent (Nelson, W. G. and A. A. Allen, 1982).	R-14
	Ice Block Removal. Once the recovery sumps have been completed and as much oil as possible has been removed from below the ice by early March, the removal of oiled ice and the pipeline repair operation commence. Equipment and staff for oiled ice removal and for pipeline repair are mobilized in February concurrent with sub-surface oil recovery.	
	Contaminated soil excavated from the pipeline trench is taken to temporary, lined containment cells at the West Dock staging area for waste classification and treatment under a contaminated soil stockpile treatment plan approved by the Unified Command and ADEC. During the oiled ice removal and the pipeline repair crew's operations in March, sorbents are used to collect oil that appears on the water surface.	
	The oil-contaminated ice is removed by trencher machines, backhoe, front-end loader, and dump trucks. Ice blocks 4-feet by 4-feet by 6-feet deep (3.6 cubic yards) are cut and lifted.	D-4 R-9
(viii) Lightering Procedures	Not applicable	Not applicable
(ix) Transfer and Storage of Recovered Oil/Water; Volume Estimating Procedure	Oil and water from recovery operations are temporarily stored in Fastanks on the temporary staging ice pads. Vacuum trucks remove the recovered fluids to temporary tanks trucked to the West Dock staging area.	R-22 S-6
	Excavated, oiled ice is loaded into dump trucks and taken to a lined storage pit at West Dock Staging Area. A lined temporary storage area is constructed to store contaminated ice excavated from the operation. The 1-acre area is constructed at West Dock Staging Area where snow and ice is piled. Liner is compat ble with crude oil.	D-5
	Liquid transfers are manifested at the West Dock staging area. Water and oil cut gauged with Coliwasa tube is logged. Measures of ice and snow end dump loads are logged.	D-1
(x) Plans, Procedures, and Locations for Temporary Storage and Disposal	The Environmental Unit includes a three-person Waste Management Team to: 1. Fill out and sign manifests, 2. Measure liquid and other waste, and 3. Submit a plan to ADEC for waste management.	 D-1 D-2 D-3

TABLE 1-32 (CONTINUED):
CRUDE OIL TRANSMISSION PIPELINE RUPTURE DURING WINTER

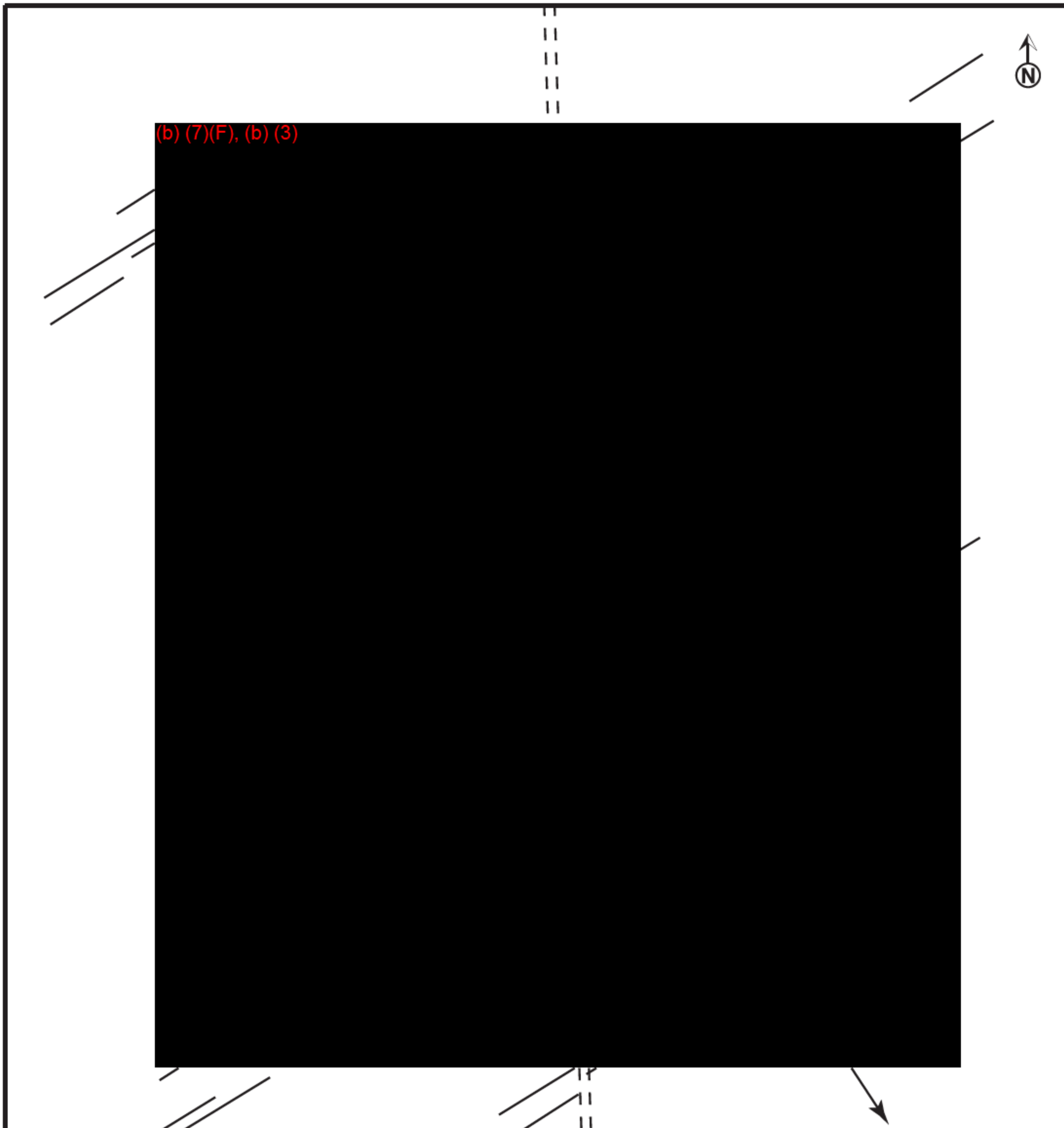
ADEC REQUIREMENT	RESPONSE STRATEGY	ACS TECHNICAL MANUAL TACTIC
(x) Plans, Procedures, and Locations for Temporary Storage and Disposal **(Continued)**	The Waste Management Team tallies the quantities and types of waste at the interim storage site at West Dock. Solid and liquid waste from DOT pipelines are disposed of in accordance with the “Alaska Waste Disposal and Reuse Guide” and consultation with the Environmental Advisor.	D-5
(xi) Wildlife Protection Plan	Polar bear and seal hole monitoring and deterrents to protect polar bears, foxes, and workers are put in place at the spill scene during recovery operations beginning Day 1. No wildlife becomes oiled.	W-1
	Trained dogs begin locating seal holes on Day 2 to support activity restrictions in their vicinity.	W-2
(xii) Shoreline Cleanup Plan	Not applicable	Not applicable



(b) (7)(F), (b) (3)

[redacted]

Filename: N1-2001071707	1" = Approx. 2.5 Miles	Figure: 1-16



[redacted]

[redacted]

Northstar Crude Oil Transmission Pipeline Rupture During Winter Under-Ice Recovery Tactics

Filename: N1-2101071707	Not to scale	Figure: 1-17

1.7 NON-MECHANICAL RESPONSE OPTIONS [18 AAC 75.425(e)(1)(G)]

BPXA will request approval for in situ burning from the State and Federal On-Scene Coordinator (SOSC and FOSC, respectively) when mechanical response methods prove ineffective or as a tool to minimize environmental damage.

Burning will not be initiated without approval of state and federal agencies. As directed by the on-scene coordinators, BPXA, and ACS will receive authorization to burn after completing the "Application and Burn Plan" form within Annex F of the Alaska Federal/State Preparedness Plan for Response to Oil and Hazardous Substance Discharges/Releases (Unified Plan). The forms are retrieved via the internet at www.akrrt.org and www.alaska.gov, respectively.

In situ burning of spilled oil will be considered under conditions such as the following:

- Mechanical recovery is impractical or ineffective,
- Shorelines are threatened,
- Burning would augment the oil elimination capacity of mechanical recovery,
- Present and forecast wind conditions will carry the smoke plume away from populated areas, and
- A successful test burn has been conducted.

If the BPXA Incident Commander decides to use in situ burning and obtains the necessary authorization, ACS will carry out the response. ACS maintains the equipment and personnel for in situ burning. The equipment and personnel are described in the ACS *Technical Manual*, incorporated here by reference. See detailed descriptions in Sections 3.4 and 3.7.

PHMSA 000109396

1.8 FACILITY DIAGRAMS [18 AAC 75.425(e)(1)(H)]

Facility diagrams are located in Volume 2 of the Northstar ODPCP.

1.9 RESPONSE SCENARIO FOR AN EXPLORATION OR PRODUCTION FACILITY [18 AAC 75.425(e)(1)(I)]

1.9.1 RESPONSE STRATEGY FOR WELL BLOWOUT CONTROL

A summary of planned methods, equipment, logistics, and time frames to control a well blowout within 15 days, required by 18 AAC 75.425(e)(1)(I), is provided below.

The estimated timeframe to secure a well blowout by means of a well-capping program is 15 days, excluding weather days and other contingencies. Mobilization of specialist teams, initial equipment and initiation of well intervention planning would be expected to take 2 days. On-site preparations would take another 3 to 4 days. Concurrently, access and safety, well capping engineering and well re-entry would be planned and decontamination facilities and off-site operations facilities would be set up. Uncontrolled fluids may be diverted for collection and handling to create a safe working environment and minimize pollution. The blow out prevention equipment (BOPE) would be removed from the well if necessary. The capping stack would be installed within several days to provide containment, and the uncontrolled release of hydrocarbons is terminated by Day 15.

Well control specialists will be notified immediately in the event of a well control situation with the potential to escalate. BPXA Alaska Drilling and Wells currently has an agreement with Boots and Coots Services, a single point of contact to provide services for well control response. Such services include, but are not limited to, firefighting equipment and services, specialty blowout control equipment and services, directional drilling services, high-pressure pumping services, and specialty fluids, chemicals and additives. The 24-hour phone numbers for Boots and Coots are found in Table 1-3.

BPXA maintains and has available fulltime on the North Slope most of the major equipment for well firefighting, to initiate well-capping, or other surface control options. Additional equipment, which may be required on a case by case basis, will be supplied through well control specialists or other vendors. Specialized equipment for well firefighting and well-capping is summarized in Table 1-33. BPXA may loan well control equipment to other North Slope operators in emergencies. The equipment mobilization and travel times in Table 1-33 do not apply to equipment loaned to other operators.

The equipment list provided in Table 1-33 presents a broad spectrum of resources that could be used during a well blowout response. Not all pieces of equipment are required to be at the staging area concurrently. The well capping team conducts activities in a preferred sequence, so tools and deliverables are on site when they are needed in the well capping process. The mobilization and travel times presented in Table 1-33 are not based upon "zero hour" of an uncontrolled release, but are estimates of the periods between the original request by the user and the equipment’s arrival at the emergency staging area. The estimates exclude weather contingencies.

Northstar’s firewater system draws water from an EDG-powered seawater pump in a sump in the warehouse. There are several firefighting stations on the island for use in the event of a fire.

The decision logic regarding well-capping response to a blowout at surface is described in Figure 1-18.

BPXA certifies that it maintains a separate well blowout contingency plan applicable for Northstar that is not part of this plan. It will be made available to ADEC upon request for inspection as stipulated by 18 AAC 75.425(e)(1)(I), .445(d)(2) and .480.

1.9.2 RESPONSE SCENARIOS FOR WELL BLOWOUTS

As a preventive measure, Northstar operations prohibit the drilling of new wells or sidetracks from existing wells into major liquid hydrocarbon zones at its drill sites during the defined periods of broken ice. The first period begins June 1 and ends July 20. The second period begins October 1 and ends with 18 inches of continuous ice cover for one-half mile in all directions from the Northstar production island.

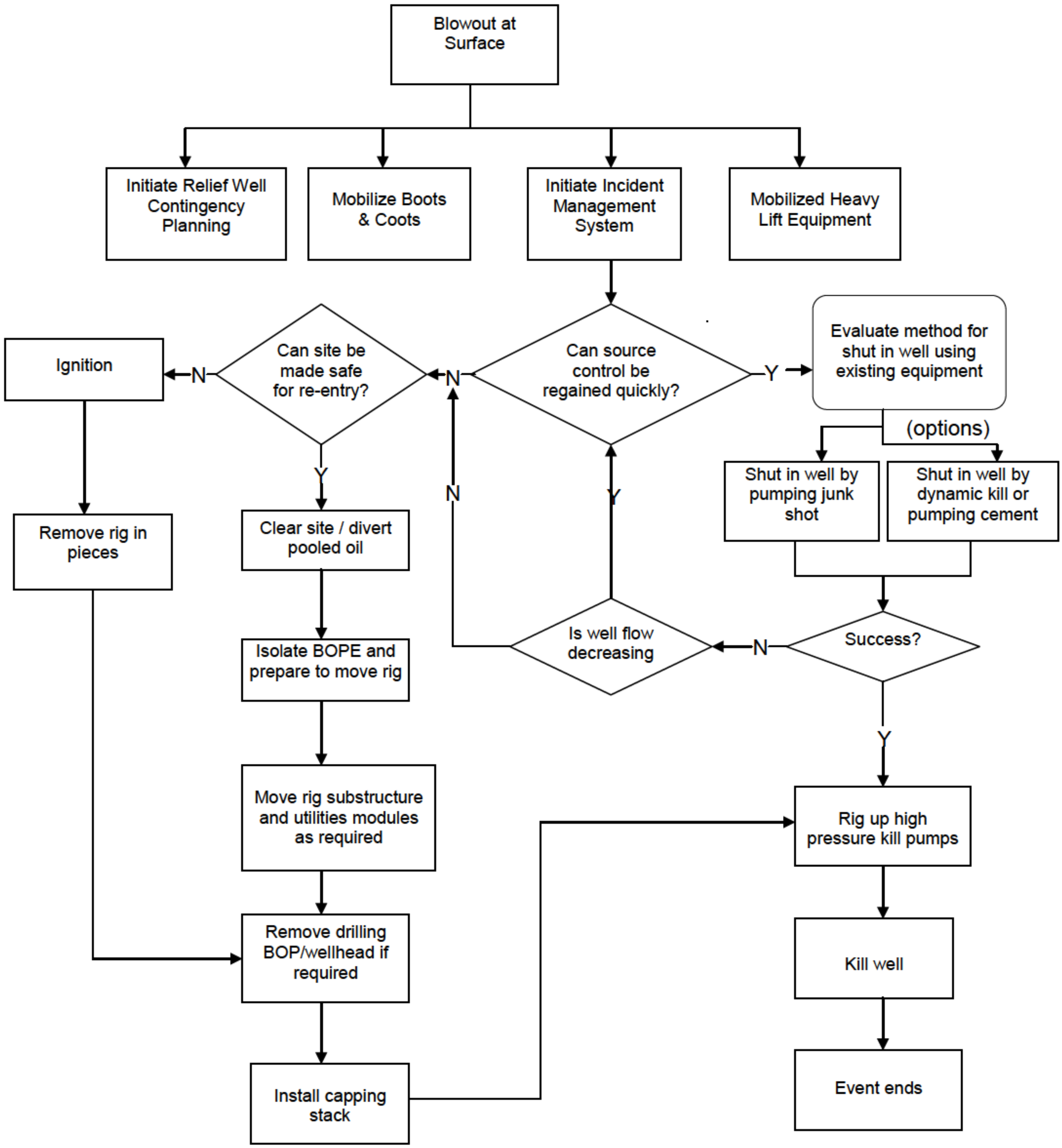
Operations will present reservoir information to the AOGCC for an AOGCC determination of which stratigraphic zones represent major liquid hydrocarbon accumulations. The AOGCC determination will be submitted to ADEC for concurrence and approval of broken ice drilling programs. The purpose of the drilling moratorium is to eliminate the environmental risk associated with a well blowout to the Beaufort Sea during broken ice conditions.

Drilling restrictions do not apply the rest of the year. Section 1.6.4 shows that the well blowout response planning standards are met in winter conditions of fast sea ice and under summer conditions of less than one-tenth sea ice coverage.

TABLE 1-33: WELL FIREFIGHTING AND CAPPING EQUIPMENT LIST

COMPONENT(S)	WELL CAPPING USAGE	LOCATION	MOBILIZATION AND TRAVEL TIME
Installed Fire Water Pump and Fire Monitors	Fire and heat suppression	Northstar	On site as part of facility infrastructure
Athey Wagon	Tractorized boom for manipulation of tools in and around blowout well	Northstar	On site
D8 Bulldozer	Power for Athey wagons and backup for heavy equipment, rig moving. Can also be used for constructing berms to aid in spill containment.	Northstar	On site
Backhoe	Drainage ditch, berm construction	Northstar / North Slope	Staged on island during shoulder seasons for immediate use, otherwise ≤8 hours
100-200 ton Crane	Heavy equipment lifting capability.	Northstar	On site
50-75 ton Crane	Smaller, mobile units for spotting support equipment	Northstar	On site
500 ton Drilling Block	Block and tackle system for moving or dragging heavy equipment	Northstar	On site
Drilling Line	Component of block and tackle system if crane is inoperable	Northstar	On site
20-inch and 30-inch Casing	Used to construct Venturi tubes to divert blowing well bore fluids (ignited and un-ignited).	Northstar	On site
Miscellaneous Equipment	High pressure chicksan, flexible hoses, valves, containment boom, absorbent, hand tools	North Slope	≤8 hours
Junk Shot Manifold	Manifold system constructed to pump small leak sealing materials into well	North Slope	≤8 hours
Hot Tap Tool	Manifold used to gain safe access to pressurized tubulars at surface	North Slope	≤8 hours
Crimping Tool	Sized device used to pinch tubulars closed to seal off internal flow	Houston, Texas	≤48 hours
Abrasive Cutter	High pressure cutting tool used to sever leaking BOPs	Duncan, Oklahoma	≤48 hours
Kill Pumps	Used to attempt dynamic kill	North Slope	Staged on island during shoulder seasons for immediate use, otherwise ≤10 days
Capping Stack	Various high pressure BOP stacks (to replace leaking, damaged or severed primary BOPs)	Houston, Texas	≤10 days
Heavy Lift Helicopter	Lifting 18,000 to 21,000 pound loads into remote or offshore locations	US Pacific Northwest	≤10 days

FIGURE 1-18: WELL CAPPING DECISION TREE



THIS PAGE INTENTIONALLY LEFT BLANK

PART 2. PREVENTION PLAN
[18 AAC 75.425(e)(2)]

Part 2, Prevention Plan, is in Volume 2.

PART 3. SUPPLEMENTAL INFORMATION [18 AAC 75.425(e)(3)]

3.1 FACILITY DESCRIPTION AND OPERATIONAL OVERVIEW [18 AAC 75.425(e)(3)(A)]

See Volume 2, Prevention Plan.

3.2 RECEIVING ENVIRONMENT [18 AAC 75.425(e)(3)(B)]

3.2.1 POTENTIAL ROUTES OF DISCHARGES [18AAC 75.425(e)(3)(B)(i)]

The Alaska Clean Seas (ACS) *Technical Manual,* Map Atlas provides maps and information on the potential routes of oil discharged from BPXA's operations, identifies containment sites, distinguishes sensitive receiving environments, and shows the latitude and longitude coordinates. ACS *Technical Manual*, Map Atlas Sheets 67, 73, 74, 78, 79, 80, 83, 86, 87, 89, 90, and 91 are incorporated by reference. Drainage from the production island and the COTP route are illustrated on the diagrams in Volume 2 (Prevention Plan), Appendix B.

3.2.1.1 OIL IN WATER AND ICE

Movement of oil released into marine waters would be primarily in response to wind, currents, and spreading mechanisms. Because currents in the area are generally wind-driven, a qualitative estimate of the likely trajectory of spilled oil under open water conditions can be determined by inspecting the wind roses for Prudhoe Bay. These data show that wind blows from the east to northeast about 60 percent of the time. Easterly winds cause a westward movement of water, creating upwelling conditions across bays, a depressed shoreline water surface, and subsequent surface water movement to the north. Winds from the west cause the water to move eastward, creating downwelling conditions, elevated water levels (+1 m) nearshore, and subsequent surface water movement to the south (shoreward).

Assuming 10-knot winds from the northeast, oil spilled at Northstar could reach the barrier island shores of Long Island. If not contained, oil moving inland through the barrier island cuts could reach the Kuparuk River Delta.

Under westerly wind conditions, oil released and not contained at Northstar Production Island would tend to move to the east. If westerly winds are sustained, downwelling conditions will be initiated in the bay and the oil will follow surface flows to the south-southeast toward Stump Island and into Prudhoe Bay. It is likely that the West Dock Causeway could block a significant portion of the onshore movement of oil.

Under prevailing easterly winds, spills along the offshore portion of the pipeline route will move toward the west and onshore toward the Kuparuk River Delta. Freshwater outflow from the Kuparuk River may cause localized changes in the movement of the oil and could keep the oil off the river delta and cause the oil to move farther toward the west and eventual landfall on the western shores of Gwydyr Bay. Under westerly winds, oil would move onshore toward Pt. McIntyre and continue east toward the West Dock area.

Oil released into the water column under a floating solid ice cover would rise and gather in pools or lenses at the bottom of the ice sheet. Oil may become trapped or entrained as new ice grows beneath the oil. Currents approaching 26 centimeters per seconds (cm/s), or 0.5 knots, would be needed to remove and transport exposed oil in subsurface depressions prior to entrainment. Typical under-ice currents along the Northstar pipeline are unlikely to exceed an average of 2 cm/s; however, currents of 10 cm/s do occur. These winter under-ice currents are unlikely to spread spilled oil beyond the initial point of contact with the ice under-surface. Research indicates that typical under-ice containment capacity for first-year landfast ice representative of the Northstar pipeline route ranges from 0.012 barrels per square foot for 25-inch-thick ice in December to 0.026 barrels per square foot for 60-inch-thick ice in April. This is equivalent to about one million barrels per square mile. As the natural containment capacity increases with ice thickness, the area to contain a given spill volume decreases steadily throughout the winter.

In broken drift ice conditions, oil will rise to the surface and either collect in the interstices or openings between individual floes, or be trapped underneath the floes themselves. During the early period of broken ice in the spring, that portion of the oil rising beneath the floes will naturally migrate through the rotting ice and appear on the ice surface within a matter of hours. In the case of oil trapped under newly forming pancakes or sheet ice in the fall, the likely fate will be rapid entrapment, with new ice quickly growing beneath the oil. The fate of oil trapped between floes will depend largely on the ice concentration and time of year.

During freeze-up, the oil will most likely be entrained in the solidifying grease ice and slush present on the water surface prior to forming an ice sheet. Storm winds at this time often break up and disperse the newly forming ice, leaving the oil to spread temporarily in an open water condition until it becomes incorporated in the next freezing cycle. At break-up, ice concentrations are highly variable from hour to hour and over short distances. In high ice concentrations, oil spreading is reduced and the oil is partially contained by the ice. As the ice cover loosens, more oil could escape into larger openings as the floes move apart. Eventually, as the ice concentration decreases, the oil on the water surface behaves essentially as an open water spill, with localized patches being temporarily trapped by wind against individual floes. Oil present on the surface of individual floes will move with the ice as it responds to winds and nearshore currents.

3.2.1.2 OIL ON ICE

Oil spilled on the ice surface in the winter is prevented from spreading rapidly by the presence of snow and natural small-scale ice-roughness features. Although the following summary is oriented to winter incidents, similar findings apply to oil on ice at freeze-up and/or break-up. It is important to note that due to the high porosity of ice at break-up, oil will lie either in the water among the floes and brash, or on the ice surface. Very little oil is likely to remain under or in the ice during break-up. Depending on the condition of the surface of the floes, oil spilled on the surface of melting broken ice may run off the surface of the hard snow-free ice and into the surrounding water or openings in the ice cover.

The spreading of oil on ice is similar to spreading of oil on land or snow. The rate is controlled by the density and viscosity of the oil, and the final contaminated area is dictated by the surface roughness of the ice. As the ice becomes rougher, the oil pools get smaller and thicker. Oil spilled on ice spreads much more slowly than on water and covers a smaller final area. As a result, slicks on stable solid ice tend to be much thicker than equivalent slicks on water. The effective containment provided by even a minimal degree of ice roughness (inches) translates to far less cleanup time with the need for fewer resources than would be needed to deal with the equivalent spill on open water.

3.2.2 ESTIMATE OF RESPONSE PLANNING STANDARD VOLUME TO REACH OPEN WATER [18 AAC 75.425(e)(3)(B)(ii)]

Zero percent of the oil from an oil storage tank on Northstar Production Island would reach open water. Approximately 85 percent, or 29,105 barrels, of the oil from a production well blowout during summer would be discharged to open water. It is estimated that approximately 2,000 barrels of the 5,320 barrels that is deposited to the production island during a summer blowout may be at risk of flowing to open water. Zero percent of the oil from a production well blowout during solid sea ice conditions would reach open water. Zero percent of the oil from a crude oil transmission pipeline spill would reach open water. See Section 1.6 for details of projected spill trajectories provided in response planning standard (RPS) volume calculations and site-specific scenarios.

3.2.3 NORTHSTAR RECEIVING ENVIRONMENT

Freeze-up occurs first in the calm, shallow water of the protected bays and lagoons, such as Simpson Lagoon, south of Long and Stump islands (October 1, ±7 days), with a range of mid-September to mid-October. The ice sheet in Simpson Lagoon remains very smooth because the area is confined by Long, Egg, and Stump islands on the north and the shoreline on the south. The ice in this area of Simpson Lagoon can be considered part of the landfast ice zone from the initial freeze-up date throughout the entire ice season.

The initiation of freeze-up at Northstar ranges from the third week of September to the fourth week in October, with a median date of October 6, ±9 days (Coastal Frontiers, 1996; Vaudrey, 1996). The vicinity of Northstar, located offshore of the barrier islands, becomes entirely ice-covered within one week after freeze-up begins.

During the nilas stage of ice growth between Stump Island and the Northstar Production Island, the ice is very susceptible to movement from strong winds. Strong winds are not unusual during freeze-up; in fact, the winds blow greater than 20 knots about 20 percent of the time during October. Assuming that these winds occur as three storms, each lasting two days, there is a 50 percent probability that at least one storm (>20 knots) will occur during the first week after freeze-up.

The young first-year ice (4 to 12 inches thick) around Northstar Island remains very susceptible to movement and deformation by winds in October. For example, on October 19-20, 1982, the 8-inch-thick young ice moved more than 20 nautical miles to the east past Seal Island, driven by 30- to 40-knot westerly winds (it should be noted that the wind direction is defined as the direction from which the wind is blowing, while the ice movement direction is defined as the direction to which the ice is moving). The rafting, minor ridging, brash ice, and refreezing open water were due to an easterly wind on October 16. During the strong westerly storm on October 19, all of the ice was blown away from the area around Seal Island.

The waves around Seal Island were at least 3 feet high during the 48-hour period (October 19-20) when the wind speeds remained between 20 and 40 knots. After the storm abated on October 21, 2 to 3 inches of ice grew within 24 hours when the air temperatures ranged from +5 degrees Fahrenheit (°F) to -5°F.

During the westerly storm on October 19-20, 1982, a number of barges broke free of their moorings along the east side of West Dock and were blown offshore of the barrier island chain east of Prudhoe Bay. While this particular storm is probably the worst in the last 20 years and may be considered to have a return period of 15 to 20 years, numerous other ice pile-up events occurred during the first 4 years of Seal Island's existence and in the region prior to island construction.

Ice pile-up events are of interest because they indicate that significant ice movement occurred around and against offshore structures and islands.

The newly forming ice sheet north of the barrier islands, especially in the vicinity of the Northstar Island, is very susceptible to deformation and movement during the 6 weeks after freeze-up occurs. The most likely scenario for freeze-up at Northstar is that a young, solid (10-tenths concentration) ice sheet will grow until conditions are present to create ice movement. All ice movement is initiated by wind stress over the ice surface; however, the single most important parameter influencing significant ice motion is the loss of confinement by the ice cover. Consequently, storm intensity and duration do not contribute as much to initiate ice movement as reversal of the wind direction, which reduces confinement through crack or lead formation. For example, an easterly wind may create an open water lead offshore of the Northstar Island and disrupt the ice sheet surrounding the island, making the ice more susceptible to movement from a southwesterly wind. In addition to loss of confinement, ice thickness and storm intensity and duration are important secondary parameters that produce ice movement. Susceptibility to ice movement is also extremely site-dependent, with exposed coasts or man-made islands in relatively deep water more at risk than protected shores of shallow bays and lagoons.

If the young ice at Northstar moves as a result of a storm with wind from the southwest, typically large ice floes (thousands of feet across) will break free of the coastline or landfast ice edge and move quickly away. This scenario tends to create open water and not necessarily broken ice around the island. Depending on how cold it is, the open water will start to refreeze, usually within a few hours to one day. This scenario may be repeated several times during freeze-up from October through mid-November, depending on the ice thickness, storm intensity, and wind direction. The broken-ice condition that occurs when the ice cracks and movement starts may be relatively short-lived; and an open-water lead, one to several miles across, usually forms in a few hours.

After the sheet ice reaches a thickness greater than 18 inches, typically by mid-November, the ice cover offshore of the barrier islands between Stump Island and the Northstar Island becomes relatively stable. In 12 years of observations, there was only one year during which an ice movement greater than 100 feet occurred during mid- to late November. Typically, by mid- to late December when the first-year ice sheet reaches a thickness of 2.5 to 3 feet, the ice in the vicinity of the Northstar Island can be considered part of the landfast ice zone.

3.2.4 WINTER ICE CONDITIONS

3.2.4.1 LATE FREEZE-UP ICE MOVEMENT

Depending on the location, the entire ice regime along the coast in the Prudhoe Bay region makes the transition from freeze-up to winter ice conditions between mid-November and late December. The onset of winter is subjective, but is usually determined by the reduced likelihood of ice movement in the floating landfast ice sheet. For instance, typical ice movement would be small (tens of feet) to nonexistent in Simpson Lagoon and along the shoreline at the Pt. McIntyre PM1 pad after the young ice sheet becomes several inches thick. There is a small but finite likelihood of large ice movements (100 feet or more) in the corridor between the Northstar Island and Stump Island or West Dock during the late freeze-up season (from mid-November to late November) when the ice thickness is usually 1.5 to 2.0 feet.

Based on six freeze-up studies from 1980 to 1985 (Vaudrey, 1981a-1986a), five years of satellite imagery collected during freeze-up in 1987-1991, and personal observations in 1995 (Coastal Frontiers, 1996), there was only one year (1983) out of 12 in which the 20-inch-thick ice moved 100 to 200 feet in this region. Note that an ice movement of a few hundred feet in November is not going to produce a broken ice situation.

Typically by mid- to late December when the first-year ice sheet becomes about 2.5 to 3 feet thick, the ice near Northstar Island becomes relatively stable, and the region becomes part of the stable landfast ice zone, which extends well beyond all of the operations sites. Ice movement on the order of 10 to 15 feet can be expected during December when the natural ice sheet is 2 to 3 feet thick.

After January 1, the risk and magnitude of ice movement is reduced significantly, as the ice sheet becomes thicker and more stable. There still is a small likelihood of a major ice movement event occurring during the winter, as documented during the late February storm in 1989. Wind speeds of 94 knots during the storm were the largest ever measured at the Deadhorse airport.

3.2.4.2 ICE SURFACE ROUGHNESS

When the ice becomes permanently landfast in the nearshore zone, it records the last major ice movement as a series of ridges, rubble formations, individual upturned blocks, and rafted ice sheets. For example, the landfast ice in central Stefansson Sound and offshore of the barrier islands at the Northstar development typically contains occasional ridges (several feet high), light rubbling, and numerous upturned ice blocks. In some years, the landfast ice is more heavily deformed. At other times, the landfast ice remains relatively flat.

The winter ice regime offshore of shoreline and causeway sites, such as Pt. McIntyre, West Dock, Niakuk, and Endicott, typically is flat indicating little or no ice motion after freeze-up. The ice surface roughness of the landfast ice varies considerably from site to site and from year to year.

3.2.4.3 MID-WINTER ICE MOVEMENT

During the landfast ice condition of winter, rapid changes in temperature may produce thermally-induced shrinkage cracks in the sheet ice, usually propagating from sources of stress concentration, such as man-made gravel islands, or promontories along the coast. In addition, a working tidal crack can be expected around any grounded ice feature or structure, such as the Northstar Production Island. Other than these minor cracking events, the first-year sheet ice in the nearshore region around the Prudhoe Bay area remains virtually motionless throughout the winter.

3.2.4.4 LANDFAST ICE THICKNESS

After the transition from freeze-up to winter, the landfast ice sheet continues to grow in situ from December through April. The sheet ice growth is generally about 1 foot per month, after achieving a thickness of about 2 feet by December 1. The landfast ice sheet attains an average maximum ice thickness of about 6 feet by April 1. Growth after April 1 slows due to warming air temperatures, but the landfast ice may add another 6 inches of thickness by the end of May.

TABLE 3-1: PREDICTED LANDFAST ICE SHEET THICKNESS

DATE	10-YEAR MINIMUM ICE THICKNESS (INCHES)	AVERAGE LANDFAST ICE THICKNESS (INCHES)	100-YEAR MAXIMUM ICE THICKNESS (INCHES)
November 1	9	13	23
December 1	21	25	36
January 1	30	36	49
February 1	41	48	62
March 1	51	60	75
April 1	61	71	84
May 1	68	77	89
June 1	72	79	90

The pipeline route from the Northstar Development is buried beneath the bottomfast ice zone prior to reaching its landfall location.

3.2.5 BREAK-UP ICE CONDITIONS

The transition from winter to break-up season begins in late April or early May, when daylight hours and air temperatures increase. Break-up is defined as the time when the ice concentration goes from 10-tenths to 9-tenths or less.

3.2.5.1 RIVER OVERFLOOD

Before the sea ice starts to show apparent signs of deterioration, melting snow in early May helps swell the upland river channels. During late May or early June, the ice in the northern Alaska rivers (e.g., Kuparuk, Sagavanirktok) breaks up about a month before the nearshore sea ice. In the shallow water depths (less than 6 feet deep) offshore of the river deltas, the landfast ice sheet typically freezes to the sea floor during the winter. This bottomfast ice forms a dam, which causes the river water to overflood the sheet ice. The overflood stage of the spring melt period is defined as Condition 5 for oil spill scenario evaluation.

The overflood water (typically 2 to 5 feet deep) on top of the floating landfast ice (in water depths of 6 to 30 feet) quickly drains through holes and cracks. The overflood water on top of the bottomfast ice (frozen to the sea floor) loosens it and allows the ice to pop up to the surface. In both cases, the top of the ice in the overflood zone is usually covered with a thin layer of silt deposited by the flood water. Typically by mid-June, about two to three weeks after the flooding has ceased, most of the landfast ice within the overflood zone will have melted in place from a combination of the fresh, relatively warm water and the increased heat absorption by the dirty ice.

3.2.5.2 SHEET ICE DETERIORATION

Warm air temperatures initiate melt pool formation on the top of the landfast ice sheet, especially where the surface is contaminated with dirt. Increased absorption of solar radiation in the dirt and meltwater, as compared to clean snow and ice, accelerates melt pond formation. However, in late May or early June at the time of river overflood, melt pools usually cover less than 10 percent of the landfast ice area beyond the overflood limits. By late June just before break-up, the number of melt pools has increased dramatically, covering approximately 40 to 50 percent of the sheet ice surface. Melt pools have a definite alignment in the direction of the principal winds (east-west orientation) since they occur in the valleys between snow drift patterns. The sheet ice deterioration stage of the spring melt period is defined as Condition 6 for oil spill scenario evaluation.

Many melt pools develop holes all the way through the sheet ice, due to enlargement of brine drainage channels. The water depths in the melt pools are highly variable, typically ranging from a few inches to slightly over 1 foot, in those areas where brine drainage holes do not exist. If the sheet ice has a typical thickness of 6 feet at the end of May, the ice loses roughly 2 feet, reaching a final thickness of about 4 feet by the time the ice breaks up around July 1. However, the “final” sheet ice thickness of 4 feet takes into account the thickness *between* melt pools (4.5 feet) and the thickness *beneath* melt pools (3.5 feet).

3.2.5.3 BREAK-UP MECHANISM

The break-up mechanism for sheet ice is related to lines of weakness that develop along a series of melt pools or old thermal or stress cracks in concert with in situ sheet ice deterioration. Initially, the sheet ice melts away from the shoreline due to river overflooding or solar radiation of dark sediment incorporated into the ice cover. Since melting of the landfast ice out to 1 to 3 miles offshore reduces confinement, wind stress may cause break-up along a line of melt pools or along existing cracks. During late June or early July, any 20-knot wind that begins to blow, probably will initiate break-up of the floating landfast ice in Steffanson Sound and offshore of the barrier island chain west of Prudhoe Bay.

3.2.5.4 TRANSITION PERIOD FROM BREAK-UP TO OPEN WATER

If the storm or strong winds that caused break-up are intense or sustained, rafting often occurs when thinner melt pool ice breaks loose and overrides the surrounding sheet ice floes. The rafting increases the amount of open water between ice floes, causing accelerated deterioration and melting by waves and currents. The period during the initial stages of break-up is defined as Condition 7 for oil spill scenario evaluation.

Once break-up occurs, the winds usually shift from one direction to the other. Broken ice floes and pans, in response to the shifting winds, move back and forth in belts and patches of varying concentrations, all the while melting rapidly. The broken ice inside the barrier islands and northwest of Prudhoe Bay moves about 0.4 to 0.5 knots during the short break-up season, but peak rates may reach 0.8 to 1.0 knots (Vaudrey and Dickins, 1996). Usually, within two to three weeks of break-up, the region around most of the bays and lagoons, such as Prudhoe Bay and Steffanson Sound, will become open water. The period during the final stages of break-up is defined as Condition 8 for oil spill scenario evaluation.

Open water is defined as 1-tenth or less ice coverage concentration. The extended summer open-water season is defined as Condition 9 for oil spill scenario evaluation.

3.2.5.5 SITE-SPECIFIC ICE CONDITIONS

The transition from winter to summer begins with the break-up of the ice in upland rivers and overflooding of the bottomfast and floating sea ice just offshore of the river deltas during late May or early June. The average date that the Kuparuk River begins to overflood the sea ice in Simpson Lagoon and offshore of Egg and Stump islands is May 29, with a standard deviation of six days, based on 16 years of data (1974-78 and 1980-90). Within a few days after the flooding begins, the water flows to the east between the coast and Stump Island and overfloods the ice along the entire west side of the West Dock Causeway. During years of heavy flooding, the water can extend to a portion of the east side of the West Dock Causeway by coming around the north end of West Dock and by flowing through the 650-foot breach. The offshore boundary of the overflood is usually the 25- to 30-foot water depth range from the north end of West Dock to eastern Long Island.

Because the shallow water along the shoreline of the PM1 pad of the Pt. McIntyre Development is within the Kuparuk River overflood zone, the bottomfast ice located here will melt in situ from the relatively warm-water discharge. By mid-June, open water exists between the Pt. McIntyre PM1 pad and Stump Island and along the shoreline to West Dock.

By early July when break-up typically occurs, there may be little or no ice in eastern Simpson Lagoon and along the west side of the West Dock Causeway; in contrast, it is likely that a completely intact, 10-tenths ice cover will exist on the east side of West Dock. Of course, the landfast ice sheet along the east side of West Dock and around the Pt. McIntyre PM2 pad will be very deteriorated, with approximately 40 to 50 percent of its surface covered by melt pools.

Break-up of the remaining floating landfast ice in Prudhoe Bay (including the east side of West Dock) and in the vicinity of the Northstar development typically occurs between the last week of June and the second week of July, with a median date of July 4. Ice concentrations during the break-up season vary

PHMSA 000109412

considerably, depending on the wind direction and intensity during July. As the winds shift from one direction to the other, the broken ice floes and pans will move back and forth in belts and patches of varying concentrations, all the while melting rapidly.

The area around West Dock and in the nearby bays, such as Prudhoe Bay and Stefansson Sound, usually becomes open water (1-tenth or less ice concentration) within three weeks after the initial break-up. Typically, open water extends from the shoreline to Seal Island by late July.

After first open water, ice invasions of greater than 1-tenth ice concentration can occur almost every summer in the area around Northstar, just offshore of the barrier islands. In severe summers, two to three ice invasions are likely to occur. One or more such invasions of 3-tenths or 5-tenths ice concentration have a 56 percent or 35 percent chance of occurrence, respectively, at the Northstar development. Summer ice invasions are less likely, but certainly do occur, in and around West Dock. There are typically 73 days between first open water and freeze-up, but the total number of days of open water is dependent on the number and duration of summer ice invasions.

3.3 COMMAND SYSTEM [18 AAC 75.425(e)(3)(C)]

The oil spill response command system is compatible with the Alaska Regional Response Team (ARRT) *Alaska Federal/State Preparedness Plan for Response to Oil and Hazardous Substance Discharges / Releases (Unified Plan)*. The organizational structure is based on the National Incident Management System. It provides clear definition of roles and lines of command, together with the flexibility for expansion or contraction of the organization. Details of the management structure in a spill response are provided in the BPXA Incident Management System (IMS), incorporated here by reference. The BPXA IMS describes the Incident Command System (ICS) position roles and responsibilities.

In most Tier I incidents, the SRT can control the incident. The Environmental Advisor fulfills the role of On-Scene Commander. The SRT steps down into the Operations Section and additional personnel become involved to fill support roles.

Tier II/III responses are initiated by the On-Scene Commander. The Incident Management Team (IMT) is activated and begins to provide support to the field responders (Operations Section) and coordinate the collection and distribution of information. The Incident Command Post is located in the Prudhoe Bay Operations Center (PBOC). ACS provides personnel and equipment resources from Deadhorse to assist in spill containment and recovery. The BPXA Business Support Team may be activated to provide additional support to the IMT. See Section 1.1 for titles of IMT members and their contact information.

ACS will be activated to stand by for spills until an assessment is performed. Once the assessment is complete, ACS is either released or mobilized. The North Slope operators coordinate with ACS to ensure a reserve of trained personnel is available for an extended spill response.

The North Slope operators view Unified Command as a structure that is created at the time of an incident to bring together the Incident Commanders of each major organization involved in response operations. For the North Slope Subarea, the Unified Command is typically comprised of the Federal On-Scene Coordinator (FOSC), the State On-Scene Coordinator (SOSC), the Local On-Scene Coordinator (LOSC), and the Responsible Party Incident Commander (RPIC). The North Slope Borough is the LOSC.

The primary responsibilities of the Unified Commanders are as follows:

- Establish objectives and priorities,
- Review and approve tactical plans developed to address objectives and priorities,
- Ensure the full integration of response resources, and
- Resolve conflicts.

These responsibilities are typically exercised through periodic, highly-focused Unified Command meetings with attendance typically restricted to Unified Command members.

As described in Part 1 of this ODPCP, the BPXA Incident Commander and the Qualified Individual are the same person.

The role of the agency representatives on the Unified Command is to fulfill their legal responsibilities (i.e., to direct and/or monitor response operations), while allowing the Responsible Party to manage emergency response operations.

When an incident occurs, the Unified Command structure may be established and superimposed at the top of the IMT. In this position, the On-Scene Coordinators are ideally situated to carry out the responsibilities cited above. They provide overall direction by establishing strategic objectives and response priorities addressed by the IMT through the planning process. Moreover, they review and approve the products of the planning process (i.e., Incident Action Plans) developed by the IMT to address the objectives and priorities.

The Unified Command position at the top of the IMT also facilitates the appropriate integration of response resources. For the agency representatives, it allows them to determine the appropriate role(s) for agency personnel and to position them optimally within the IMT structure. For the Responsible Party, it ensures members of the IMT have access to valuable expertise without diluting their ability to manage response operations.

3.4 REALISTIC MAXIMUM RESPONSE OPERATING LIMITATIONS [18 AAC 75.425(e)(3)(D)]

3.4.1 INTRODUCTION

Realistic maximum response operating limitations that might be encountered at the facility are described in the ACS *Technical Manual*, Volume 1, Tactic L-7, which is incorporated into the plan by reference. Tactic L-7 analyzes the frequency and duration, expressed as a percentage of time, of limitations that would render mechanical response methods ineffective, as required by 18 AAC 75.425(e)(3)(D). The analysis considers weather, sea conditions, ice, daylight hours, and other environmental conditions that might influence the efficiency of the oil spill response.

This section describes additional specific response measures that will be taken to reduce the environmental consequences of an oil spill to ice conditions.

3.4.2 WEATHER AND ICE CONDITIONS DURING THE SHOULDER SEASONS

The following general description of break-up and freeze-up describes typical marine conditions in the Prudhoe Bay region. They cover the chronology of break-up and freeze-up. See Dickins et al., (2000) and tables in Atwater (1991) for further site-specific details.

3.4.2.1 MAY

The Sagavanirktok River and Kuparuk River overfloods (Condition 5) commence on average May 20 and 27, respectively, based on 16 years of analysis. See DF Dickins Associates et al., (2000) for descriptions of seasonal ice conditions.

3.4.2.2 JUNE

June 1-10: Landfast ice is intact (Condition 4) beyond the Kuparuk River and Sagavanirktok River overflood boundaries. Within the overflood zones immediately off the river deltas, fast ice lifts off the bottom of the Beaufort Sea and rapidly melts in place from the relatively warm water discharge (Conditions 6 and 7). The peak of major flooding occurs during the period June 4-7 (±6 days), at which point the Kuparuk River overflood may reach within one mile of the Northstar Island (Condition 5). Routine ice road operations might cease at this time. First open water appears offshore of the Sagavanirktok River and Kuparuk River by June 6 to 13, respectively, on average. Fast ice beyond the overflood zones and outside the barrier islands is still intact and more than 5 feet thick in early June.

June 15-20: Nearshore lagoon areas affected by the Kuparuk overflood and shallow waters off the Sagavanirktok delta become mostly free of ice (Condition 9). Fast ice offshore remains intact (e.g., Stump Island to Northstar) and continues to melt (Condition 7). Solid ice 4 to 5 feet thick still surrounds Northstar Island. The soft surface is 25 percent covered by meltwater pools (Condition 6).

Air temperatures average 35°F and range from 20° to 40°F. The wind is variable, but blows 60 percent of the time from the east and northeast, averaging 10 knots.

The ice can support response vehicles up to several weeks before break-up. The effect of deteriorating sea ice on access with specific equipment is illustrated in ACS *Technical Manual*, Tactic L-7, based on field trials by Coastal Frontiers (2001).

3.4.2.3 JULY, AUGUST AND SEPTEMBER

July 1: A completely intact, deteriorated ice cover 3 to 4 feet thick, with many cracks and approximately 40 to 50 percent of its surface covered by melt pools and holes still exists in deeper water in the vicinity of Northstar (Condition 6).

July 4 (Typical): Break-up begins with fracturing and movement in the floating landfast ice (Condition 7).

July 8-12: Remaining fast ice outside the barrier islands, off the Sagavanirktok River delta and in Prudhoe Bay decreases to less than 7 tenths coverage (Condition 8).

July 15-26: Open, ice-free water out to Northstar and surrounding West Dock and Endicott causeway (Condition 9).

Air temperatures average 40°F in July.

The median number of days with flooded and/or broken ice at break-up at production facilities ranges from 12 days at Point McIntyre to 22 days at Northstar.

3.4.2.4 OCTOBER

Oct 4, ±8 days: Freeze-up begins along shore in shallow water. Ice becomes shore fast for the season within one week following freeze-up in the nearshore lagoons (e.g., Point McIntyre 2 and Niakuk) and by October 25 offshore.

Additional time is required for the young ice sheet to gain sufficient thickness and stability to be judged safe for over-ice operations. Time from initial freeze-up to being able to commence on-ice operations with response equipment ranges on average from 40 to 43 days at coastal or nearshore locations such as Point McIntyre 1, Niakuk, and Endicott, to 55 days at the Northstar.

Air temperatures at freeze-up range from 5°F to 15°F. Daylight is 9 to 10 hours per day.

3.4.3 IN SITU BURNING RESPONSE MEASURES TO REDUCE ENVIRONMENTAL CONSEQUENCES OF A SPILL IN ICE CONDITIONS

Oil spill removal during the shoulder seasons can be greatly enhanced by in situ burning. Cold water and ice provide containment and slow the weathering process, thereby concentrating the oil for burning and recovery. In situ burning in shoulder season ice conditions generally involves selective burning of oil on melt pools and in leads between floes, followed by manual recovery of residue.

3.4.3.1 OPERATIONAL CAPABILITY FOR IN SITU BURNING IN ICE

ACS maintains an inventory of specialized equipment for in situ burning operations during shoulder season ice conditions.

The ACS *Technical Manual* describes response strategies, procedures, and equipment to implement a successful burn in a mix of solid ice, broken ice and open water situations. The tactics descriptions are listed below and are incorporated by reference into the plan.

- B-1 In Situ Burning Plan
- B-2 Burning Oily Vegetation
- B-3 In Situ Burning with Helitorch and Other Igniters
- B-4 Deployment and Use of Fire Containment Boom
- B-5 Burning Oil Pools on any Solid Surface
- B-6 Residue Recovery
- B-7 Burn Extinguishment on Water (applicable to fire booms in light ice cover)

ACS conducts spill response training courses involving classroom and field exercises to practice the burn tactics described in the ACS *Technical Manual* several times per year at North Slope locations.

The training involves a classroom course and a field demonstration with burn pans. The Helitorch is discussed in the classroom and shown in the warehouse. Demonstrations can also involve creating and igniting gelled fuel. Alyeska Pipeline Service Company has pilots familiar with the Helitorch operations and its helicopter is set up for the Helitorch attachment.

The ACS inventory of specialized response equipment on hand to support a large scale burning operation is summarized in Table 3-2.

TABLE 3-2: BURNING EQUIPMENT

EQUIPMENT	QUANTITY
Helitorch	7
Helitorch Surefire gel	1,200 pounds
Air deployable igniters	1,480
Helitorch batch gel mixers	2

Adapted from ACS inventory – Response Equipment Specifications, ACS *Technical Manual*, Tactic L-6

In addition, ACS maintains over 18,000 feet of fire-resistant boom ranging in overall height from 20 to 30 inches, together with specialized logistics vehicles to access spill sites over a rotting and/or flooded ice surface in May and June (e.g., airboats). See Tactic L-6 tables describing boom and vessels.

Once state and federal approval is granted, the following steps are taken to implement the response:

1. Collect and concentrate the oil using fire-resistant booms in light ice cover or utilize naturally occurring pools of thicker oil in high ice concentrations and on surface melt pools on solid ice break-up, and in slush and new ice at freeze-up.

2. Ignite the oil using the Helitorch or hand-held igniters, following established safety procedures to avoid flashback or ignition of any ongoing spill source.

3. Monitor the burn, maintaining constant watch on the fire and smoke plume, condition of containment booms (if used), and other safety hazards and issues.

4. Recover and dispose of the burn residue.

Safety procedures and planning in accordance with established guidelines are emphasized throughout the training, preparation, and conduct of in situ burning operations.

In situ burns are monitored to ensure that fire does not spread to adjacent combustible material. Care is taken to control the fire and to prevent secondary fires. Personnel and equipment managing the process are protected. The safe working distances from an in situ fire on water depend on the size of the fire and the exposure time, and are summarized in Table 3-7.

Aerial ignition with gel by Helitorch or other ignition methods is coordinated, taking into account prevailing weather conditions, oil pool size and distribution, and the need for strict adherence to established safety distances. A detailed discussion of the determination of safety distances can be found in Annex F of the Unified Plan.

Crews practice the techniques involved with in situ burning at sea that could involve several vessels working in close proximity.

3.4.3.2 EFFECTIVENESS OF IN SITU BURNING IN ICE

The consensus of research on spill response in broken ice conditions is that in situ burning is an effective response technique, with removal rates exceeding 90 percent in many situations (Shell et al., 1983; SL Ross, 1983; SL Ross and DF Dickins, 1987; Singsaas et al., 1994; SL Ross et al., 1998; DF Dickins et al., 2000; Sørstrøm et al., 2010). The research includes several smaller-scale field and tank tests (SL Ross et al., 2003; Shell et al., 1983; Brown and Goodman, 1986; Buist and Dickins, 1987; Smith and Diaz, 1987; Bech et al., 1993; Guénette and Wighus, 1996; Sørstrøm et al., 2010) and a few large field tests (Singsaas et al., 1994 and Sørstrøm et al., 2010). Most of the tests involved large volumes of oil placed in a static test field of broken ice, resulting in substantial slick thicknesses for ignition. The few tests in unrestricted ice fields or in dynamic ice have indicated that the efficacy of in situ burning is sensitive to ice concentration and dynamics. Important variables include: the tendency for the ice floes to naturally contain the oil, the thickness (or coverage) of oil in leads between floes, and the presence or absence of brash or frazil ice which can absorb the oil.

Brash ice is the debris created when larger ice features interact and degrade. Frazil ice is the "soupy" mixture of very small ice particles that form as seawater freezes.

Oil spilled on solid ice or among broken ice in concentrations equal to or greater than 6-tenths has a high probability of becoming naturally contained in thicknesses sufficient for combustion. In lower ice concentrations, oil spill response methods can be used to create and maintain sufficient film thickness to facilitate burning. Fire-resistant booms are examples. Field experience has shown that it is the small ice pieces (e.g., the brash and frazil, or slush, ice) that accumulate with the oil against the edges of larger ice features (floes) and control the concentration (e.g., thickness) of oil in an area, and control the rate at which the oil subsequently thins and spreads. Other factors affecting burn effectiveness include oil weathering processes (e.g., evaporation and emulsification) and mixing energy from waves.

The following discussion summarizes the scientific principles and physical processes involved for in situ burning of oil on melt pools during the ice melt phase in June or on water between floes during the break-up period in July, based on SL Ross et al., (2003). Further discussion also covers in situ burning of thinner slicks in mobile broken ice comprised of brash or frazil ice during the freeze-up shoulder season in October.

The success of an in situ burning operation is highly dependent upon slick thickness.

For an oil slick on water or ice to become ignited, the oil must be thick enough to insulate itself from the water beneath it. The igniter can heat the surface of thickened oil to the flash point temperature at which the oil produces sufficient vapors to ignite. The rules of thumb for minimum ignition thickness are listed in Table 3-3.

TABLE 3-3: MINIMUM IGNITABLE THICKNESS ON WATER ADAPTED FROM BUIST ET AL. (2003)

OIL TYPE	MINIMUM THICKNESS
Light Crude and Gasoline	1 millimeter (mm) (0.04 inch)
Weathered Crude and Middle-Distillate Fuel Oils (Diesel and Kerosene)	2 to 3 mm (0.08 to 0.12 inch)
Residual Fuel Oils and Emulsified Crude Oils	10 mm (0.4 inch)

The oil removal rate for in situ oil fires is a function of fire size (or diameter), slick thickness, oil type and ambient environmental conditions. For most large (greater than 3-meter diameter) fires of unemulsified crude oil on water, the "rule- of-thumb" is a burning consumption rate of 3.5 millimeters per minute (mm/min). Lighter fuels burn faster, and heavier oils and emulsions burn slower, as shown in Table 3-4.

TABLE 3-4: BURN/REMOVAL RATES FOR LARGE FIRES ON WATER ADAPTED FROM BUIST ET AL., (2003)

OIL TYPE/CONDITION	BURN/REMOVAL RATE
Gasoline >10 mm (0.4 inch) thick	4.5 mm/min (0.18 inch per minute)
Distillate Fuels (diesel and kerosene) >10 mm (0.4 inch) thick	4.0 mm/min (0.16 inch per minute)
Crude Oil >10 mm (0.4 inch) thick	3.5 mm/min (0.14 inch per minute)
Heavy Residual Fuels >10 mm (0.4 inch) thick	2.0 mm/min (0.08 inch per minute)
Slick 5 mm thick[1]	90 percent of rate stated above
Slick 2 mm thick[1]	50 percent of rate stated above
Emulsified oil (percent of water content)[2]	Slower than above rates by a factor equal to the water content percent

Estimates of burn/removal rate based on experimental burns and should be accurate to within ±20 percent.

[1] Thin slicks will naturally extinguish, so this reduction in burn rate only applies at the end of a burn.

[2] If ignited, emulsions will burn at a slower rate almost proportional to their water content (a 25 percent water-in-crude-oil emulsion burns about 25 percent slower than the unemulsified crude).

Burn rate is also a function of the size of the fire. Crude oil burn rates increase from 1 mm/min with 3-foot diameter fires to 3.5 mm/min for 15-foot fires and greater. In situ burns on melt pools typically consume oil at 1 mm/min. For very large fires, on the order of 50 feet in diameter and larger, burn rates may decrease slightly because there is insufficient air in the middle of the fire to support combustion at 3.5 mm/min. As fire size grows to the 50-foot range, oil type ceases to affect burn rate for the same reason.

An in situ oil fire extinguishes naturally when the slick burns down to a thickness that allows enough heat to pass through the slick to the water to cool the surface of the oil below the temperature required to sustain combustion. The thickness at which an oil fire on water extinguishes is related to the type of oil and initial slick thickness. The rules of thumb are presented in Table 3-5. Other secondary factors include environmental effects, such as wind (winds greater than 20 knots preclude in situ burning in most cases) current herding of slicks against barriers, and oil weathering.

TABLE 3-5: FIRE EXTINGUISHING SLICK THICKNESS ADAPTED FROM BUIST ET AL., (2003)

OIL TYPE/INITIAL SLICK THICKNESS	EXTINGUISHING THICKNESS
Crude Oil up to 20 mm (0.8 inch) thick	1 mm (0.04 inch)
Crude Oil 50 mm (2 inches) thick	2 to 3 mm (0.08 to 0.12 inch)
Distillate Fuels any thickness	1 mm (0.04 inch)

With an estimate of the initial thickness of a fully-contained slick, or a measure of the burn time, it is relatively easy to estimate oil removal efficiency by burning. If not all the slick area is on fire; the calculations need to account for this.

Oil removal efficiency by in situ burning may be summarized as a function of the following key factors:

- Initial thickness of the slick,
- Thickness of the residue remaining, and
- Amount of the slick's surface that was on fire.

Oil thickness is maintained by water current in the apex of a fire-resistant boom under tow or against an ice edge in wind or current. When burning in a current, the fire slowly decreases in area until it reaches a size that can no longer support combustion. This herding effect can increase overall burn efficiencies, but it extends the time required to complete each burn.

The residue from a typical, efficient (greater than 85 percent removal) in situ burn of crude oil 10 to 20 millimeters thick is a semi-solid, tar-like layer that has an appearance similar to the skin on an old, poorly-sealed can of latex paint that has gelled. For thicker slicks, typical of what might be expected in a towed fire boom (about 150 to 300 millimeters), the residue can be a solid. Burn residue is usually denser than the original pre-burn oil, and usually it does not spread due to its increased viscosity or solid nature.

Tests indicate that the burn residues from efficient burns of heavier crude oils, <32 degrees API, may sink once the residue cools, but their acute aquatic toxicity is very low or nonexistent. The “In Situ Burning Guidelines for Alaska, Revision 1” (ADEC, U.S. Environmental Protection Agency and USCG, March 2008) state:

> “In general, however, the effects [biological effects of burn residues] are less severe than those from a large, uncontained oil spill, and no specific biological concerns have been identified to date (ASTM, 2003).”

Compared with unemulsified slicks, emulsions are much more difficult to ignite and, once ignited, display reduced flame spreading and more sensitivity to wind and wave action. Stable emulsion water contents are typically in the 60 to 80 percent range with some up to 90 percent. The oil in the emulsion cannot reach a temperature higher than 100 degrees Celsius (°C) until the water is either boiled off or removed. The heat from the igniter or from the adjacent burning oil is used initially to boil the water rather than heat the oil.

The following points summarize the effect of water content on the removal efficiency of weathered crude emulsions:

- Little effect on oil removal efficiency (i.e., residue thickness) for water contents up to 12.5 percent by volume;
- A noticeable decrease in burn efficiency with water contents above 12.5 percent, the decrease being more pronounced with weathered oils;
- Zero burn efficiency for emulsion slicks having water contents of 25 percent or more; and
- Some crudes form meso-stable emulsions that can burn efficiently at much higher water contents. Paraffinic crudes appear to fall into this category.

Fortunately, emulsion formation is slowed dramatically by high ice concentrations and may not be a significant operational factor in planning in situ burns on solid ice or naturally contained in higher concentrations of broken ice.

SL Ross et al., (2003) provides guidelines for burning thin slicks in broken ice with brash and slush, particularly relevant during the break-up and freeze-up shoulder seasons. General rules for minimum ignitable thickness and oil removal rates for burning thin slicks of crude oils on brash and/or slush with broken ice are as follows:

- The minimum ignitable thickness for fresh crude on frazil ice or small brash ice pieces is up to double that on open water, or about 1 to 2 millimeters.
- The minimum ignitable thickness for weathered crude oil on frazil ice or small brash ice pieces can be higher than on open water, but is still within the range quoted for weathered crude on water, about 3 millimeters with gelled gasoline igniters.
- For a given spill diameter, the burn rate in calm conditions is about halved on relatively smooth frazil/slush ice and halved again on rougher, brash ice. Wave action slightly reduces the burn rate on open water, but the halving rule appears to apply in waves as well.
- The residue remaining on broken ice in calm conditions is about 50 percent greater than that on open water, or 1.5 millimeters. The residue remaining on brash or frazil ice in waves is slightly greater than in calm conditions, at about 2 millimeters.

In summary, in situ burning of oil is efficient and rapid in broken ice conditions under the following conditions:

- The spilled oil is thicker than the minimum ignitable thickness (a thickness of 2 millimeters to 3 millimeters results in 50 to 66 percent removal efficiency: 10-millimeter thickness, a typical thickness for wind-herded slicks on melt ponds on ice, gives 90 percent removal efficiency);
- Larger areas can be ignited (a 100-square-foot slick on a melt pool will burn at 3.5 barrels of oil per hour [boph]; a 50-foot diameter, 10-millimeter thick slick will burn at 300 boph, and a 100-foot diameter slick will burn at 1,200 boph);
- The oil is not more than 25 percent emulsified; and
- Herding in a current and enlarging fire diameters can increase burning rates.

3.5 LOGISTICAL SUPPORT [18 AAC 75.425(e)(3)(E)]

BPXA has an existing logistical support infrastructure for its operations on the North Slope. Transportation equipment, coordination procedures, and maintenance procedures are in place under normal operations. BPXA has contracts for operational logistical support to support a spill response.

ACS *Technical Manual* Tactics L-3, L-4, and L-8 through L-10 are incorporated here by reference.

3.6 RESPONSE EQUIPMENT [18 AAC 75.425(e)(3)(F)]

3.6.1 EQUIPMENT LISTS

Contracted or other oil discharge containment, control, cleanup, storage, transfer, lightering, and related response equipment to meet the applicable RPS in Part 1, and to protect environmentally sensitive areas and areas of public concern identified in Part 3, and that may be reasonably expected to suffer an impact from a spill of the RPS volume as described in Part 1, is listed as required by 18 AAC 75.425(e)(3)(F)(i) to (vii). The location, inventory, and ownership of ACS-managed equipment listed in the RPS scenarios in Part 1 is listed in the ACS *Technical Manual* Tactic L-6, and in the *Technical Manual*'s tactics descriptions incorporated by reference in the scenarios in Part 1. The time frame for delivery and startup of response equipment and trained personnel located outside the North Slope is outlined in the response scenarios in Part 1. The manufacturer's rated capacities, limitations, and operational characteristics for each item of oil recovery equipment listed in the scenarios in Part 1 are listed in the ACS *Technical Manual* Tactic L-6 and in the *Technical Manual* tactics descriptions incorporated by reference in the scenarios. Each vessel and the equipment for transferring oil from tanks mentioned in the scenarios in Part 1 is listed in Tactic L-6 as well.

A list of dedicated oil spill response equipment positioned on Northstar is provided in Table 3-6.

3.6.2 MAINTENANCE AND INSPECTION OF RESPONSE EQUIPMENT

Response equipment is routinely inspected, maintained, and tested by ACS according to written standard operating procedures.

ACS holds the following Oil Spill Removal Organization (OSRO) classifications for facilities and vessels:

- River/Canal and Inland – MM, W1, W2, and W3; and
- Nearshore, Offshore, and Open Ocean – MM, W1, and W2.

ACS has fulfilled the equipment maintenance and testing criteria that the classifications require.

3.6.3 PRE-DEPLOYED AND PRE-STAGED EQUIPMENT

Oil spill preparedness includes boom pre-deployment and the staging of spill response equipment at selected areas. SRT personnel deploy diversionary and exclusion boom in rivers each summer. With each year’s experience operating in rivers, the staging of equipment and sites has varied. The goal is to strategically locate the staged equipment in proximity to potential leak sources, and in areas that are easily accessible, allowing for the quick deployment of additional equipment if needed. Gravel pads near the rivers can be used as additional staging areas. Additional boom deployment sites, boat launches, and staging areas are evaluated annually.

Due to seasonal changes of the river channels and to weather conditions causing fluctuating river currents, specific boom-laying configurations, and footage lengths of boom pre-staged at each site vary. Boom sections and anchors are staged on the shoreline in a manner that optimizes their use for containment and recovery.

Pre-staged equipment is described in the ACS *Technical Manual*, Volume 2, Sheets 67, 73, 74, and 79, which are incorporated here by reference.

TABLE 3-6: NORTHSTAR ON-SITE SPILL RESPONSE EQUIPMENT

QUANTITY	UNIT OF MEASURE	DESCRIPTION	LOCATION
2	each	Boat, Spill Response, 24-feet. Aluminum Hull	Northstar in summer Prudhoe in winter
2	each	Boat, Spill Response, 42-feet. (Bay Class)	West Dock
2	each	249 bbl Mini Barges	West Dock
2	each	LORI LSC-3 Skimmer	West Dock
500	foot	Boom, Fire 12-inches x 18-inches	West Dock
2,000	foot	Boom, Ro-Boom (2 reels) 27-inches x 32-inches	Northstar
2,000	foot	NOFI Fast Deployment Boom	Northstar
2	each	Bird Scare Cannons	Northstar
1	each	Wildlife Hazing Kit	Northstar
1	each	Wildlife Capture and Stabilization Kit	Northstar
10	each	Breco Bird Scare Buoys	Eight at ACS Base Two at Northstar
2	each	2,400 Gallon Fastank	Northstar
1	each	All-terrain Vehicles (ATV) with tracks	Northstar
2	each	Connex, Storage Container 20-feet x 8-feet	Northstar
1	each	Connex, Insulated & Wired Shop 20-feet x 8-feet	Northstar
1	each	Portable Drum Skimmer (dual surface interchangeable)	Northstar
1	each	Vertical Rope Mop, 2 Mop	Northstar
1	each	100 Gallon Fuel Tank	Northstar
2	each	Hand Held Global Positioning System	Northstar
2	each	Light Stand and Cords	Northstar
2	each	Generator, 6 kW and 4.5 kW Diesel	Northstar
1	each	Pump, Diaphragm 3-inch Diesel	Northstar
1	each	Pump, Marine Trash 2-inch Diesel	Northstar
2	each	Pump, Trash 3-inch Diesel	Northstar
200	foot	Hose, 2-inch Discharge, Arctic Grade	Northstar

TABLE 3-6 (CONTINUED): NORTHSTAR ON-SITE SPILL RESPONSE EQUIPMENT

QUANTITY	UNIT OF MEASURE	DESCRIPTION	LOCATION
100	foot	Hose, 2-inch Suction, Arctic Grade	Northstar
700	foot	Hose, 3-inch Discharge	Northstar
500	foot	Hose, 3-inch Suction	Northstar
10	each	MISC. Kamlok Adapters	Northstar
1	each	Fold-a-Tank, 1500 gallon	Northstar
2	each	18-inch x 18-inch Surface Liner	Northstar
2	each	36-inches x 42-inches Surface Liner	Northstar
4	each	4-foot x 5-foot surface liners	Northstar
2	roll	20-foot x 100-foot Reinforced Visqueen	Northstar
10	each	Rolls, Sorbent 36-inches x 150-foot	Northstar
4	each	Bundles, Glycol Sorbent Pads 18-inch x 18-inch	Northstar
12	each	Bundles, Sorbent Boom 8-inch x 10-foot, 40-foot per Bundle	Northstar
13	each	Bundles, Sorbent Pads 18-inch x 18-inch	Northstar
18	each	Bundles, Sorbent Pads 36-inch x 36-inch	Northstar
2	each	Fence Post Driver (Northstar)	Northstar
24	each	Fence Posts (Northstar)	Northstar
1	each	Rope, 1/2-inch Polypropylene, 600-feet per Roll	Northstar
2	each	Rope, 3/4-inch Polypropylene, 600-feet per Roll	Northstar
4	each	Rake, Steel Garden	Northstar
4	each	Shovels, Aluminum Scoop	Northstar
4	each	Shovels, Round Point	Northstar
4	each	Shovels, Square Nose	Northstar
4	lot	Survey Lathe and Flagging	Northstar
10	each	Hand-held Ignitors for In Situ Burn	Northstar
1	each	Snowblower	Northstar
1	each	Chain Saw	Northstar
1	each	Ice Auger	Northstar
1	each	Vicoma Power Vac Unit	Northstar
1	each	Multi - Gas Meter	Northstar

TABLE 3-6 (CONTINUED): NORTHSTAR ON-SITE SPILL RESPONSE EQUIPMENT

QUANTITY	UNIT OF MEASURE	DESCRIPTION	LOCATION
COMMUNICATION EQUIPMENT			
1	each	Marine Private Coast Station	Northstar
6	each	MT2000 Hand-held Radios	Northstar
1	each	Backboarded Spectra Mobile Radios	Northstar
GWYDYR BAY EQUIPMENT			
3	each	Connex	West Dock
2,000	foot	Delta Boom, 8-in. x 6-in.	West Dock
2,000	foot	NOFI 250 EP Boom Bag	West Dock
3	each	Anchoring System (tote, two 66 lb. Bruce anchors, line, buoys)	West Dock
12	each	Anchors (40 lb. with rigging)	West Dock

3.7 NON-MECHANICAL RESPONSE INFORMATION [18 AAC 75.425(e)(3)(G)]

In situ burning equipment inventory and deployment is described in the ACS *Technical Manual* Tactics L-6 and B-1 through B-7, which are incorporated here by reference.

The Northstar sales oil exhibits properties making it amenable to burning (ACS, 2010). Its density ranges from 0.80 grams per cubic centimeter for fresh oil at 15 degrees Celsius (°C) to 0.88 grams per cubic centimeter for 55 percent weathered oil at 1°C. The oil's viscosity ranges from 1.7 milliPascal seconds (mPas) when fresh and at 15°C to 5,363 mPas when weathered 55 percent and at 1°C. The American Society for Testing and Materials Standard D97 pour point is below the method limit for fresh oil; the pour point is 18°C for 55 percent weathered oil. Fresh oil is unlikely to emulsify regardless of whether it is near freezing or at higher ambient temperatures. Weathered oil that has lost almost half its mass to evaporation has some emulsification likelihood at near-freezing temperature and may have a water content from 17 percent to 49 percent. Maximum weathering (i.e., 55 percent loss) makes the oil more likely to form an emulsion with water content of approximately 35 to 39 percent.

3.7.1 ENVIRONMENTAL CONSEQUENCES

The environmental consequences of in situ burning will be assessed by monitoring the downwind trajectory of the smoke. A trial burn will indicate the path of the smoke. Monitoring the downwind position of the smoke plume will be accomplished by a ground- or air-based member of the IMT.

Appropriate measures as required by the Unified Command, natural resource agencies, and public safety agencies will be carried out to protect nearby human populations and environmentally sensitive areas. In situ burns will be limited to sites that are a minimum safe distance, generally several miles upwind of human populations. The safe distance will be plotted as outlined in Annex F of the Unified Plan. The determination takes into account a trial burn, wind conditions, and size of the expected burn area. In addition, public notifications and warnings will be issued in cooperation with agency emergency staff.

In situ burns conducted according to the Unified Plan are not expected to harm environmentally sensitive areas and areas of public concern. Heat from in situ burning affects only the upper few centimeters of the water column in contact with the oil. Smoke has not been found harmful to wildlife populations. In situ burning smoke is reduced to concentrations that are safe to people by means of burning only at safe distances.

In situ burn operations receive constant visual monitoring of the smoke plume's behavior. The burn operations team visually monitors the smoke plume. The federal and state on-scene coordinators may authorize a trial burn to confirm anticipated plume drift direction and dispersion distances downwind before authorizing the proposed burn. Burn operations may be stopped if the plume contacts or threatens to contact the ground in a populated area.

A step-by-step process in establishing safe distances for burning is fully presented in Annex F of the Unified Plan. The state and federal on-scene coordinators determine whether the burn lies at a safe distance from human populations. In situ burning is not authorized if it does not meet public health regulatory standards. The safe distance separating human populations from in situ oil burns is the downwind radius from the fire at which smoke particulate matter concentrations at the ground diminish to limits established by National Ambient Air Quality Standards. The safe distance guidelines are based on the predictions of a National Institute of Standards and Technology (NIST) computer model, ALOFT-Flat Terrain model. The safe distance meets the National Ambient Air Quality Standards for particulate matter over a one-hour time period and is also used as the indicator that human populations will not be exposed to unsafe levels of all other smoke components. Table 3-7 lists the general safe distances separating an in situ burn and downwind, populated areas in flat terrain.

TABLE 3-7: SAFE DISTANCES BETWEEN IN SITU BURNS AND DOWNWIND HUMAN POPULATIONS IN FLAT TERRAIN: LOCATION OF FIRE ZONES

LOCATION OF FIRE	GREEN ZONE	YELLOW ZONE	RED ZONE
Flat terrain on land	>3 miles	1 to 3 miles	<1 mile
Water <3 miles from shore			
Water >3 miles from shore	>1mile	Not applicable	<1 mile

Burning at a green zone safe distance from the public is acceptable following public notification.

Annex F allows the results of the NIST modeling to be used to authorize burning on the North Slope. The results show that for fires up to 10,000 square feet in area (about 100 feet in diameter, in all wind speeds modeled over land or water in typical winter and summer atmospheric conditions), the surface concentrations of particulate matter decline below the target concentration in less than 0.6 mile of the burn. Fifty-six scenarios in Cook Inlet and the North Slope were modeled using the ALOFT-FT computer model, and the worst-case predictions were used to develop the safe distances for those specific locations.

3.7.2 OPERATIONAL CAPABILITY

ACS maintains specialized equipment to conduct in situ burning operations during all seasons and all ice conditions. The extensive inventory of response equipment is specifically designed to support a large-scale burning operation. See Section 3.4.3, In Situ Burning Response Measures to Reduce Environmental Consequences of a Spill in Ice Conditions, for details.

3.7.3 EFFECTIVENESS OF IN SITU BURNING IN ICE

The consensus of research on spill response in broken ice conditions is that in situ burning is an effective response technique with removal rates exceeding 85 percent in many situations (Shell et al. 1983, SL Ross 1983, SL Ross and DF Dickins 1987, Singsaas et al. 1994, SL Ross et al. 1998, DF Dickins et al. 2000, Sørstrøm et al. 2010). See Section 3.4.3, In Situ Burning Response Measures to Reduce Environmental Consequences of a Spill in Ice Conditions, for details).

PHMSA 000109431

3.8 RESPONSE CONTRACTOR INFORMATION [18 AAC 75.425(e)(3)(H)]

BPXA will activate ACS and the North Slope members of ACS to provide the initial manpower and resources for a large or lengthy spill response. The address and phone number for ACS is shown in Part 1. If additional resources are required, they will be accessed through Master Services Agreements maintained by ACS. BPXA's Statement of Contractual Terms with ACS is provided in the Introduction.

3.9 TRAINING AND DRILLS FOR SPILL RESPONSE PERSONNEL [18 AAC 75.425(e)(3)(I)]

3.9.1 NORTH SLOPE SPILL RESPONSE TEAM TRAINING

The North Slope Spill Response Team (NSSRT) consists of workers who volunteer as emergency spill response personnel. Each team member is required to have initial emergency response training and annual refresher training, which meets or exceeds the requirements in the Hazardous Waste Operations and Emergency Response (HAZWOPER) regulations, 29 CFR 1910.120(q). Annual requirements for HAZWOPER refreshers, medical physicals, and respiratory fit tests are tracked by ACS through weekly reports from the database. At intervals not exceeding 15 months, but at least once each year, BPXA makes changes to its emergency response training program to maintain its effectiveness in compliance with 49 CFR 195.403(b). The NSSRT training program is provided to responders from all production units on the North Slope.

Response training and attendance is documented and available for review. The yearly training schedule is also available at the facility and ACS Base. Current NSSRT training schedules are posted on the ACS web site.

The minimum NSSRT staffing levels on the North Slope are illustrated in Table 3-8. The staffing levels represent the largest shift demand within the first 72 hours for each responder classification derived from the scenarios presented in Section 1.6. Responders are classified into five categories each with minimum training requirements as noted below.

TABLE 3-8: SPILL RESPONSE TEAM MINIMUM STAFFING LEVELS

RESPONDER CLASSIFICATION	NUMBER
General Technician	58
Skilled Technician	51
Team Leader[1]	Included among vessel operators
Vessel Operator-Nearshore	10
Vessel Operator-Offshore	9
Total Technicians and Operators	128

[1] Team Leaders number are included among Vessel Operators.

3.9.1.1 GENERAL TECHNICIAN

The General Technician is a responder with minimal or no field experience in spill response. Duties are associated with mobilization, deployment and support functions for the response. Support tasks such as deployment of boom sections, assembly of anchors systems, assembly of temporary storage devices, loading and unloading equipment, and decontamination of equipment are typical tasks undertaken by this responder classification. Responders in this classification must have a current 24-hour (or higher) HAZWOPER certificate.

Over time, the NSSRT training program brings NSSRT members from General Technician to at least the Skilled Technician level.

3.9.1.2 SKILLED TECHNICIAN

The Skilled Technician is a responder who has experience in spill response activities at a higher level through specific training, related activities as part of regular employment, or in spill response incidents. Tasks such as the operation of skimmers, powerpacks, and transfer pumps are typical tasks undertaken by this responder. Responders in this classification have documentation of training as listed below:

- Minimum training requirements for the General Technician, and
- Completion of 16 hours of training or equivalent experience in any combination of the following categories:
  - Response equipment deployment and use;
  - Response tactics and equipment requirements;
  - Emergency response management (ICS);
  - Staging area management and support;
  - Boat safety, navigation, or operations;
  - Contingency plan familiarization, and
- Completion of 16 hours of actual spill response, response exercise, or field deployment time in any combination of the following positions:
  - Operation of recovery equipment systems;
  - Operation of transfer and storage equipment systems;
  - Deployment and use of containment systems;
  - Decontamination procedures;
  - Wildlife hazing, capture and stabilization, and
- Ten completed equipment proficiency checks.

3.9.1.3 TEAM LEADER

Team Leader roles may include such categories as Task Force Leader, Containment or Recovery Site Team Leader, or Staging Area Manager. A team leader is described as an individual who has attended additional training in the actions, responsibilities, and tasks associated with managing portions of an incident. Responders in this classification have documentation of training as follows:

- Training requirements for the General Technician,

- Training requirements for the Skilled Technician,
- Current 8-hour (or higher) HAZWOPER Supervisor certification, and
- Twenty completed equipment proficiency checks.

3.9.1.4 VESSEL OPERATOR-NEARSHORE

Responders qualified as Vessel Operator-Nearshore, are tasked with safe operation of vessels less than 30 feet in length. The vessels have a hull design and electronics primarily intended for operation in nearshore environments or occasionally, in conjunction with larger vessels, in an offshore response. Typical duties include towing and placement of containment booms, setting and tending anchors, and movement of equipment to remote sites. Responders in this classification have documentation of training as listed below:

- Training requirements for the General Technician, and
- Criteria for any one of the following categories:
  - Completion of the ACS, Captain and Crew or Boat Safety and Handling Training Programs;
  - Completion of 40 hours of equivalent training or experience on vessels smaller or greater than 30 feet including navigation, charting, vessel electronics, and docking and maneuvering procedures;
  - Current USCG Operator Uninspected Passenger Vessel, or higher license; and
- Completion of Nearshore Vessel proficiency check.

3.9.1.5 VESSEL OPERATOR-OFFSHORE

Responders qualified as Vessel Operator-Offshore are tasked with the safe operation of vessels larger than 30 feet in length. The vessels have a hull design and electronics capable of sustaining operations in an offshore environment. Typical duties include the towing of containment booms, working in conjunction with barge containment operations, towing mini barges, operating skimmers to recover oil, providing ice management support, and providing logistical support to offshore operations. Responders in this classification have documentation of training as follows:

- Training requirements of the General Technician, and
- Criteria for any one of the following:
  - Completion of the ACS, Captain and Crew Training Program;
  - Completion of 40 hours of equivalent training or experience on vessels larger than 30 feet including navigation, anchoring, vessel electronics, and docking and maneuvering procedures; and
  - Current USCG 25-Ton Near Coastal or larger license; and
- Completion of Offshore Vessel proficiency check.

3.9.1.6 ACTIVE MEMBER REQUIREMENTS

NSSRT members must complete minimum annual training activities to be considered an active member of the NSSRT. The training requirements include 8-hour HAZWOPER refresher certification and plan review.

The NSSRT training program offers weekly classes at each field. The classes emphasize hands-on experience, field exercises, and team-building drills. The courses are selected by the ACS Environmental Lead Technician in conjunction with field management and use BPXA, ACS, and external training consultants. Table 3-9 lists typical NSSRT training courses. Many are divided by subject area and taught in the two- or three-hour time frame of an NSSRT meeting.

TABLE 3-9: NORTH SLOPE SPILL RESPONSE TEAM TRAINING PROGRAM COURSES

CATEGORY	COURSE TITLE
Communication	ICS Basic Radio Procedures
Decontamination	Decontamination Procedures
Environmental	Environmental Awareness
	Wildlife Hazing
Equipment	Basic Hydraulics for Spill Responders
	Boom Construction and Design
	Fastanks and Bladders
	Skimmer Types and Application
	Snow Machines and ATV Operations
	90 Spill Response Equipment Proficiency Checks
Management	Incident Command System
	Quarterly Drill and Exercises
	Staging Area Management
Miscellaneous	Global Positioning System
Response Tactics	In Situ Burning
	Nearshore Operations
	Summer Response Tactics
	Winter Oil Spill Operations
	Winter Response Tactics
Safety/Survival	Arctic Cold Weather Survival
	Arctic Safety
	HAZWOPER
	Spill Site Safety
	Weather Port and Survival Equipment
	Arctic Cold Water Survival
Vessel-Related	Airboat Operations
	Boat Safety and Handling
	Boom Deployment on Rivers
	Captain/Crewman Vessel Training
	Charting and Navigation
	Deckhand/Knot Tying
	River Response School
	Swiftwater Survival

3.9.2 INCIDENT MANAGEMENT TEAM MEMBER TRAINING

A description of the North Slope IMT training program is provided in Volume 3, Section 6.0, of the ACS *Technical Manual*, incorporated by reference. The training program meets or exceeds the National Preparedness for Response Exercise Program (NPREP) guidelines. The training program is also compliant with the National Incident Management System (NIMS). All ACS Training Specialists are NIMS Certified 300 and 400 level trainers. ACS provides ICS training for its own personnel and for some BPXA North Slope IMT personnel. The training includes an introduction to the Incident Command System (ICS-100), Basic Incident Command System (ICS-200), Intermediate Incident Command System (ICS-300), Advanced Incident Command System (ICS-400), Incident Command System position-specific training workshops, tabletop exercises, and deployment drills. As new training needs are identified, they are developed and incorporated into the ACS ICS training program.

The incident management system training program includes an introduction to new members of the IMT, position-specific training, and the process flow. The program is designed to be provided in a progressive manner that leads personnel through the entire operational planning period for an incident. Table 3-10 provides a summary of the training modules.

Tabletop exercises and drills test knowledge and competency of the system. When additional training or response procedures are identified, training programs or workshops are designed to address the identified issue. Current training schedules are available at the facility and on the ACS website.

Full training records of NSSRT response team members and contractors are maintained and available for inspection at the ACS Base in Deadhorse.

BPXA trains its IMT members based in Anchorage, called the Alaska Response Team. BPXA maintains a database of the training courses taken by each employee. Training includes ICS overview, section-specific training, and tabletop drills. Records are kept for a minimum of three years or for the entire time that the employee is assigned responsibilities in this plan. The database provides a brief description of the course and the date completed. Current training status of employees is available upon request.

TABLE 3-10: NORTH SLOPE INCIDENT MANAGEMENT SYSTEM TRAINING MODULES

MODULE NUMBER	COURSE
ICS-100	Introduction to the Incident Command System
ICS-200	Basic Incident Command System
ICS-300	Intermediate Incident Command System
ICS-400	Advanced Incident Command System
ICS-236	Stating Area Manager Workshop
ICS-341	Incident Response Planning Workshop
ICS-342	Documentation Unit Leader Workshop
ICS-346	Situation Unit Leader Workshop
ICS-348	Resources Unit Leader Workshop
ACS-1	Plan Development Unit Leader Workshop
ACS-2	Tabletop Exercise
ACS-3	Integrated Field Deployment and IMT Tabletop Exercise

3.9.3 SPILL RESPONSE EXERCISES

BPXA has adopted the NPREP guidelines. Participation in the NPREP and use of its guidelines ensure federal exercise requirements mandated by the Oil Pollution Act of 1990 (OPA 90) are met.

Internal exercises are conducted within BPXA to test the components of this plan for response to a spill. Components tested through the exercise program are as follows:

- Quarterly Qualified Individual Notification Drills are conducted to ensure the Qualified Individual is able to be reached on a 24-hour basis in a spill response emergency and carry out assigned duties.
- Annual Spill Management Team Tabletop Exercises are conducted to ensure personnel are familiar with the contents of this plan, including the Incident Command System, crisis response procedures, mitigating measures, notification telephone numbers and procedures, and individual roles in the response structure.
- Semi-Annual Equipment Deployment Exercises are conducted to ensure internal and contractor-operated response equipment is fully functional and can be deployed in an efficient and productive manner.
- A triennial exercise of the entire plan is conducted.
- Government-initiated unannounced exercises are conducted.

The North Slope Crisis Management / Emergency Response (CM/ER) Coordinator is responsible for ensuring that an internal unannounced exercise meeting NPREP requirements occurs annually. The Planning Section Chief is responsible for documenting actions taken during an actual event for NPREP credit if it involves one of the following:

- Use of emergency procedures to mitigate or prevent a discharge or threat of a discharge,
- Activation of the field IMT, or
- Deployment of spill response equipment.

With the exception of government-initiated unannounced exercises, the internal exercises are self-evaluated and self-certified. Documentation, including a description of the exercise, objectives met, and results of evaluations, is maintained for a minimum of 5 years. Exercise documentation is in written form, signed by the ACS Environmental Lead Technician for each exercise, and available for review upon request. The CM/ER Coordinator will be responsible for coordinating exercise documentation.

The North Slope CM/ER Coordinator and the ACS Environmental Lead Technician or designee are responsible for the scheduling, development and evaluation of oil spill response training programs and exercises, and for ensuring that regulatory requirements are met.

External exercises involve efforts outside of BPXA to test the interaction between BPXA and the response community. The external exercises also test the plan and the coordination between BPXA and the response community. The response community comprises the OSRO (ACS); state, federal, and local agencies; and local community representatives.

BPXA participates in an annual Mutual Aid Drill (MAD). In addition to actively participating in the MAD, federal, state, and local agencies are involved in the development and evaluation of the drill. Components tested through the MAD exercise are as follows:

- Organizational Design
    - Notifications (includes training on 24-hour notifications and reporting to the National Response Center),
    - Staff mobilization, and
    - Ability to operate within the response management system described in the plan;
- Operational Response
    - Discharge control;
    - Assessment of discharge;
    - Containment of discharge;
    - Recovery of spilled material;
    - Protection of economically and environmentally sensitive areas;
    - Disposal of recovered product, and
- Response Support
    - Communications;
    - Transportation;
    - Personnel support;
    - Equipment maintenance and support;
    - Procurement, and
    - Documentation.

3.10 PROTECTION OF ENVIRONMENTALLY SENSITIVE AREAS [18 AAC 75.425(e)(3)(J)]

Northstar crude oil is a persistent product. Many of its aromatic hydrocarbon compounds are toxic to fish, wildlife, and humans at various exposures.

Priority protection sites, sensitivities, surface water flow directions, wildlife protection strategies, and natural resources are described in the ACS *Technical Manual* Map Atlas, Volume 2, and are subject to confirmation by the resource agencies.

Mapped predictions of oil spill trajectories are provided in the scenarios in Part 1. The effect of seasonal conditions on the sensitivity of wildlife and areas to be given priority attention are depicted in “Information on Seasonal Sensitivities” and on Sheets 58 through 62, respectively, in the ACS *Technical Manual* Map Atlas, Volume 2.

On a regional scale, environmentally sensitive areas are incorporated by reference from the North Slope Subarea Contingency Plan. The maps include (but are not limited to): geographic response strategy (GRS) sites, biologically sensitive areas, Most Environmentally Sensitive Areas (MESA), and the Environmental Sensitivity Index (ESI). The most current maps can be accessed at the following link:

http://www.asgdc.state.ak.us/maps/cplans/subareas.html#northslope

3.11 ADDITIONAL INFORMATION [18 AAC 75.425(e)(3)(K)]

Not Applicable.

3.12 BIBLIOGRAPHY [18 AAC 75.425(e)(3)(L)]

Alaska Clean Seas, *Technical Manual*. Prudhoe Bay, Alaska. http://www.alaskacleanseas.org/tech-manual/

Alaska Regional Response Team (ARRT), 2010. *The Alaska Federal/State Preparedness Plan for Response to Oil and Hazardous Substance Discharge/Releases (Unified Plan)*. Change 3. http://dec.alaska.gov/spar/perp/plans/uc.htm

ARRT. 2010, *Chemical Countermeasures: Dispersants, Chemical Agents, and Other Spill Mitigating Substances, Devices or Technology, Annex F.* Unified Plan. http://dec.alaska.gov/spar/perp/plans/uc/Annex%20F%20(Jan%2010).pdf

ARRT. 2012*. Wildlife Protection Guidelines for Alaska, Annex G, Rev. 5.* Unified Plan. http://dec.alaska.gov/spar/perp/plans/uc/Annex%20G%20(Oct%202012).pdf

ARRT. 2012. North Slope Subarea Contingency Plan. Change 2. http://dec.alaska.gov/spar/perp/plans/scp_ns.htm and http://www.asgdc.state.ak.us/maps/cplans/subareas.html#northslope

Atwater, S.G. 1991. 1990 Endicott Environmental Monitoring Program Final Report: Ice Break-up and Freeze-up. Prepared by SAIC for the U.S. Army Corps of Engineers, Anchorage AK.

Atwater, S.G., 1991. 1989 Endicott Environmental Monitoring Program Final Report: Ice Break-up and Freeze-up. Prepared by SAIC for the U.S. Army Corp of Engineers, Anchorage, AK.

BP Exploration (Alaska), Inc. 2010. *2010 BP Team Alaska Safety Handbook,* Anchorage, Alaska.

Bech, C., P. Sveum, and I. Buist. 1993. The Effect of Wind, Ice and Waves on the In Situ Burning of Emulsions and Aged Oils. Proceedings of the Sixteenth Arctic and Marine Oilspill Program Technical Seminar, Calgary, AB. pp 735-748.

Bronson, M. 1998. In Situ Burning Safe Distance Predictions with ALOFT-FT Model. Prepared by EMCON Alaska, Inc., for the Alaska Department of Environmental Conservation.

Bronson, M. 2000. Oil Spill Equipment Tests in Alaska Beaufort Sea, Spring 2000. Prepared for Alaska Clean Seas.

Bronson, M. 2000. Oil Spill Equipment Tests in Alaska Beaufort Sea, Fall 2000. Prepared for Alaska Clean Seas

Bronson, M., Thompson, E, McAdams F. and J. McHale. 2002. Ice Effects on Barge-based Oil Spill Response Systems in the Alaskan Beaufort Sea. Proceedings 25th Arctic and Marine Oilspill Program Technical Seminar (AMOP), Calgary, pp 1253-1268.

Brown, H.M. and R.H. Goodman. 1986. In Situ Burning of Oil in Experimental Ice Leads. Environmental Studies Revolving Funds Report 064. National Energy Board, Calgary.

Buist, I.A. and D.F. Dickins. 1987. Experimental Spills of Crude Oil in Pack Ice. Proceedings of the 1987 Oil Spill Conference, April 6-9, Baltimore, Maryland. American Petroleum Institute, Washington, D.C. pp 373-382.

Buist, I., T. Coe, D. Jensen, S. Potter, L. Anderson, K. Bitting and K. Hansen. 2003. In Situ Burn Operations Manual. USCG Report CG-D-06-03, U.S. Coast Guard Research and Development Center, Groton, CT. pp 157.

Campbell , T.E., Taylor, E. and D. Aurand. 1994. Ecological Risks Associated with Burning as a Spill Countermeasure in a Marine Environment. Proceedings of the 17th AMOP Technical Seminar, June 8-10, Vancouver, British Columbia, pp. 707-716.

Coastal Frontiers Corporation. August 2001. Spring Breakup Equipment Access Test Program. For BP Exploration (Alaska) Inc., Anchorage.

ConocoPhillips Alaska, Inc. and BP Exploration (Alaska) Inc. 2005. North Slope Environmental Field Handbook. February.

Danenberger, E.P. Minerals Management Service. 1993. Outer Continental Shelf Drilling Blowouts 1971 – 1991. Presented at the 25th Annual Offshore Technology Conference in Houston, Texas, U.S.A., 3-6 May 1993.

DF Dickins Associates Ltd., Vaudrey & Associates Inc., and SL Ross Environmental Research Limited. 2000. *Oil Spills in Ice Discussion Paper*. Prepared for Alaska Clean Seas, Prudhoe Bay, Alaska.

Dickins, D.F. and K. Vaudrey. 2000. Typical Environmental Conditions During Freeze-Up in Nearshore Alaskan Beaufort Sea. Prepared for Alaska Clean Seas.

Dickins, D.F. Associates Ltd. 1997. Late Winter Spill Response & Pipeline Repair,

Dickins, D.F. Associates Ltd. 2001. “Summary Tables – Wind Speed, Direction and Persistence.” Memo report to BP Exploration (Alaska) Inc.

Izon, D., Danenberger, E.P. and Mayes, M.. Minerals Management Service. 2007. Absence of Fatalities in Blowouts Encouraging in MMS Study of OCS Incidents 1992-2006. Article based on a presentation for the IADC Well Control Conference of the Americas, 28-29 August 2007, Galveston, Texas.

Guénette, C.C. and R. Wighus. 1996. In Situ Burning of Crude Oil and Emulsions in Broken Ice. Proceedings of the 19th AMOP Technical Seminar. Calgary, AB. pp 895-906.

McCourt, J., I. Buist, S. Buffington. 2001. Results of laboratory tests on the potential for using in situ burning on seventeen crude oils. Proceedings of the 2001 International Oil Spill Conference, pp. 529 to 532.

Nelson, W. G. and A. A. Allen, 1982. The Physical Interaction and Cleanup of Crude Oil with Slush and Solid First Year Ice, Proceedings of the Fifth Arctic Marine Oil Spill Program Technical Seminar, pp 37-59.

Potter, S. 2006. Investigations of Conditions for Flow of Weathered Endicott Crude Oil: Endicott Slump Test. SL Ross Environmental Research Ltd. for BP Exploration (Alaska) Inc. 18 pp.

SL Ross Environmental Research Ltd. 1983. Evaluation of Industry's Oil Spill Countermeasures Capability in Broken Ice Conditions in the Alaskan Beaufort Sea, for Alaska Department of Environmental Conservation, Anchorage.

SL Ross Environmental Research Ltd. and DF Dickins Associates Ltd. 1987. Field Research Spills to Investigate the Physical and Chemical Fate of Oil in Pack Ice. Environmental Studies Revolving Funds Report No. 062. 95 p.

SL Ross Environmental Research Ltd. 1997. Oil Deposition Modeling for Surface Oil Well Blowouts. June.

SL Ross Environmental Research Ltd., 2000. In-air Evaporative Losses of Oil from Surface Blowouts. Prepared for Alaska Clean Seas, Prudhoe Bay, Alaska.

SL Ross Environmental Research Ltd. 2001. Spill Related Properties and Dispersant Effectiveness of Northstar NS-31 Crude Oil. Prepared for BP Exploration (Alaska) Inc.

SL Ross Environmental Research Ltd., 2006. Spill Related Properties of Eleven Crude Oils from the North Slope of Alaska. For Alaska Clean Seas, Prudhoe Bay.

SL Ross Environmental Research Ltd., DF Dickins Associates Ltd. and Alaska Clean Seas. 2003. Tests to Determine the Limits of In Situ Burning of Thin Oil Slicks in Broken Ice. Report prepared for the US Minerals Management Service and ExxonMobil Upstream Research.

SL Ross Environmental Research Ltd., D.F. Dickins and Associates Ltd., and Vaudrey and Associates, Inc. 1998. Evaluation of cleanup capabilities for large blowout spills in the Alaskan Beaufort Sea during periods of broken ice. Alaska Clean Seas and Dept. of the Interior Minerals Management Service on behalf of the North Slope Spill Response Project Team. Prudhoe Bay, Alaska.

SL Ross Environmental Research Ltd. and Energetex Engineering. 1986. Decision-Making Aids for Igniting or Extinguishing Well Blowouts to Minimize Environmental Impacts. Environmental Studies Revolving Funds, Report No. 051. Environment Canada

Sandwell Engineering Inc. 2001. Ice Access Guidelines for Spill Responders, Report prepared for ACS.

Scandpower A/S. 2001. Blowout frequency assessment of Northstar. Report No. 27.83.01/R1. July 2, 2001. By H. Johnen, T. E. Nielsen and J. Olsen for BP Exploration (Alaska), Inc. 40 pages and appendices.

Scandpower A/S. 2010. Blowout and Well Release Frequencies based on SINTEF Offshore Blowout Database 2009. Report No. 80.005.003/2010/R2. October 8, 2010. By T. Nordvik. 67 pages.

Shell Oil Company, Sohio Alaska Petroleum Company, Exxon Company, U.S.A., Amoco Production Company. 1983. Oil Spill Response in the Arctic - Part 2: Field Demonstrations in Broken Ice., Shell Oil Company, Sohio Alaska Petroleum Company, Exxon Company, U.S.A., Amoco Production Company. Anchorage, Alaska.

Singsaas, I., P. Brandvik, P. Daling, M. Reed and A. Lewis. 1994. Fate and Behaviour of Oils Spilled in the Presence of Ice - A comparison of the results from recent laboratory, meso-scale flume and field tests. Proceedings of the 17th AMOP Technical Seminar, June 8-10, Vancouver, British Columbia, pp 355-370.

Smith, N.K. and A. Diaz. 1987. In-Place Burning of Crude Oils in Broken Ice. Proceedings of the 1987 Oil Spill Conference, April 6-9, Baltimore, Maryland. American Petroleum Institute, Washington, D.C. pp 383-387.

Sørstrøm, S.E., P.J. Brandvik, I. Buist, P. Daling, D. Dickins, L. Faksness, S. Potter, J.F. Rasmussen and I. Singsaas. 2010. Oil in Ice – Joint Industry Program on Oil Spill Contingency for Arctic and Ice Covered Waters, Summary Report.

Veltkamp, B. and Wilcox, J.R. 2007. Nearshore Beaufort Sea Meteorological Monitoring and Data Synthesis Project. Prepared for the U.S. Department of the Interior, Minerals Management Service, Alaska OCS Region. September.

Zhang, T., T. E. Osterkamp, and K. Stamnes, 1996. Some characteristics of the climate in northern Alaska, Arctic and Alpine Res., 28(4), 509-518.

PART 4. BEST AVAILABLE TECHNOLOGY [18 AAC 75.425(e)(4)]

Part 4 addresses best available technology (BAT) requirements in 18 Alaska Administrative Code (AAC) 75.425(e)(4)(A), (B), and (C). This Part also addresses technologies not subject to response planning standards or performance standards in 18 AAC 75.445(k)(1) and (2). The discussion of each technology complies with the requirement to analyze applicable technologies and to provide justification that the technology is the best available.

4.1 COMMUNICATIONS [18 AAC 75.425(e)(4)(A)(i)]

The communications system for use in a spill response is described in the Alaska Clean Seas (ACS) *Technical Manual*, Volume 1, Tactic L-11, incorporated here by reference.

4.2 SOURCE CONTROL [18 AAC 75.425(e)(4)(A)(i)]

4.2.1 WELL SOURCE CONTROL

The two methods of regaining well control once an incident has escalated to a surface blowout scenario described in Part 1 are well capping and relief well drilling. BP Exploration (Alaska), Inc. (BPXA) investigations indicate that well capping constitutes the BAT for source control of a blowout.

4.2.1.1 WELL CAPPING

Well capping techniques have proven efficient and effective in regaining well control and reducing environmental impacts. BPXA conducted a thorough investigation of well capping to regain control of a well blowout. The investigation used the response planning standard (RPS) conditions for exploration or production drilling as the evaluation case. Inherent in this evaluation are the assumptions that primary and secondary levels of well control have failed and that all dynamic and mechanical attempts to regain primary or secondary well control have been ineffective. The assessment considered best available techniques and methods to control a deep well blowout with the potential of releasing liquid hydrocarbons to the surface.

Well capping response operations are highly dependent on the severity of the well control situation. BPXA has the ability to move specialized personnel and equipment, e.g., capping stack or cutting tools, to North Slope locations upon declaration of a well control event. The materials to execute control (e.g., junk shots, hot tapping, freezing, or crimping), are small enough that they can be quickly made available to remote locations, even by aircraft, as necessary.

BPXA has an inventory of well control firefighting equipment warehoused on the North Slope. This equipment includes two 6,000 gallons per minute (gpm) fire pumps, associated piping, lighting, transfer pumps, Athey wagons, specialized nozzles, and fire monitor shacks. The equipment represents a standard array of firefighting and well control equipment normally mobilized by well control specialists in a blowout event. Maintaining this equipment on the North Slope significantly minimizes the time to mobilize and transport well control response equipment in an actual blowout event.

Other equipment for well capping operations are commonly available items on the North Slope, e.g., cranes, tanks, pumps, block and tackle, and large diameter casing. Well capping equipment available to Northstar operations is described in Section 1.9.

Well capping is both compatible and feasible with drilling operations because the technology is applied at the surface. There are no sensitivities to well types, e.g., extended reach drilling, horizontal, or location. Well capping techniques have been applied both on land and at offshore locations and have historically proven successful in regaining well control within a short duration. Well capping techniques are preferred over the more time-consuming alternative of drilling a relief well.

BPXA maintains an operating agreement with Boots and Coots Services, a worldwide well control specialist organization that can assist in the intervention and resolution of a well control emergency. This alliance of global service providers gives BPXA access to the best fit-for-purpose technology in response to a variety of emergency responses.

In an actual blowout event, well capping operations would commence with BPXA’s activation of Boots and Coots Services and mobilization of key Incident Management Team personnel, as well as deployment of select equipment. Dynamic and surface well control methods may continue in the interim only if it is approved and safe to do so. If the well capping option were selected and approved, safe re-entry to the wellhead area would be established and well capping operations would commence.

Other than the initial cost of the well control equipment currently stationed on the North Slope, maintaining an open contract with Boots and Coots Services is a minimal annual cost. Additional services required during an actual response would be provided at previously agreed upon rates.

The U.S. Bureau of Safety and Environmental Enforcement (BSEE) and SINTEF Civil and Environmental Engineering (Norway) data indicate that well capping technologies provide the shortest duration and most effective option for regaining well control and minimizing environmental impacts. This is seen in the more consistent application of well capping in response to well control events and the correspondingly shorter durations to successfully regain well control as compared to the few relief wells that have been attempted.

BPXA, in conjunction with well control experts from Boots and Coots Services, developed a schedule of events for conducting a well capping operation. This estimate does not take into account the high probability that well flow may be significantly reduced or stopped in the interim by formation bridging, dynamic kill operations, or surface well control actions. Forward plans require an iterative review process as well conditions change.

If involuntary ignition has not occurred, voluntary ignition of the blowout may also be considered as a method to reduce the volume of oil that falls to water as well as reduce the potential of secondary explosive events. The decision of voluntary ignition must be a carefully considered option as it may result in an explosive event due to trapped compartmentalized gasses within the well house. Voluntary ignition with subsequent explosive events may impact safe access to the wellhead area, which may in turn alter response operations.

4.2.1.2 RELIEF WELL DRILLING

Relief well drilling technology is compatible to North Slope drilling operations although it may be sensitive to both the well location and well types. Multiple drilling rigs are under contract on the North Slope. Downhole and surface equipment, e.g., tubulars and wellheads, to support relief well drilling operations are also available.

Relief well drilling is similar to current methods used to drill and complete North Slope wells today, and advances in directional drilling technology allow more precise wellbore placement, increasing the likelihood of success of a relief well. However, relief well attempts would be more sensitive to blowout well locations or blowout well types for a facility having unique logistical challenges. For extended reach wells or remote locations, relief well drilling would be both challenging and time consuming.

Well control events where relief well drilling would be the preferred source control method involve events in which the potential to release liquid hydrocarbons to the surface is highly unlikely, e.g., shallow gas, compromised surface casing or surface casing cement jobs, broaching or reasonable concern of broaching, inaccessible wellhead and/or casing.

Government (Danenberger, 1993; and Izon, Danenberger, Mayes, 2007) and industry data (Scandpower A/S, 2001 and 2010) indicate that for a vast majority of the occurrences well control was regained through conventional dynamic kill procedures, surface control measures, well capping, or by natural means, e.g., formation bridging.

Optimal surface locations are rarely available on the North Slope and, as such, relief well drilling is often the least desirable option.

Relief well drilling to a deep zone blowout below surface casing can be a time consuming and costly process. If access to the blowout location is unavailable, alternative locations must be sourced and/or constructed, e.g., access roads, gravel pads in the summer, or ice pads in the winter. After permitting, site construction, well planning and rig mobilization, the relief well must still be drilled. Onshore North Slope relief well durations are often estimated in the 40- to 90-day range. These lengthy timelines add to the overall environmental impact (spill volume) of the blowout well. Based on historical data (Scandpower A/S, 2001), it is estimated that more than 97 percent of blowouts would be under control by other means by the time the relief well drilling rig could be mobilized.

Relief wells provide the longest duration alternative of effectively regaining well control. In addition to the longer blowout duration, the relief well itself introduces additional environmental risks. If access to a site near the blowout well is limited, a new gravel or ice site must be quickly constructed. If gravel is required, there would be an impact to the tundra where gravel is placed. During equipment mobilization or relief well drilling operations, additional risks of spills and tundra impacts are possible. During the drilling of the relief well itself, the risk for a second well control event is introduced.

BPXA believes well capping constitutes BAT for well source control. In the event of a blowout, BPXA deems it prudent to also activate a separate team to pursue a relief well plan parallel and independent of the primary well capping plan. This action is to ensure an alternate plan is being formulated and maturing for quick implementation if required. Table 4-1 summarizes well capping as BAT. Historical evidence clearly indicates well capping has greater reliability and application for well blowout control compared to that of relief well drilling.

TABLE 4-1: BEST AVAILABLE TECHNOLOGY ANALYSIS WELL BLOWOUT SOURCE CONTROL

BAT EVALUATION CRITERIA	EXISTING METHOD: WELL CAPPING	ALTERNATE METHOD: RELIEF WELL DRILLING
AVAILABILITY: Whether technology is best in use in other similar situations or is available for use by applicant	Well capping is in use globally. Fit-for-purpose well capping and well control equipment is located on the North Slope. Additional equipment can be on location within a few days.	Relief well drilling equipment (rigs, downhole tools, etc.) is available, though not widely USED. If extended reach drilling is required to intercept the affected wellbore rig selections become limited.
TRANSFERABILITY: Whether each technology is transferable to applicant's operations	Equipment is currently available on North Slope or on retainer via Boots and Coots Services contract.	Multiple drilling rigs are currently under contract and current rig-sharing agreement has been signed by North Slope operators.
EFFECTIVENESS: Whether there is a reasonable expectation each technology will provide increased spill prevention or other environmental benefits	Numerous global companies provide successful applications of well capping. After natural bridging and conventional methods (BOP, mud, cementing, equipment repairs, etc.), well capping is most frequent blowout control measure. Application of well capping provides best opportunity for minimizing pollution impacts.	Rare successful application of relief well drilling has been documented in industry. Industry data suggest a very small percentage of blowouts are successfully controlled with this technique. Relief well drilling at 40 to 90 days is the longest pollution mitigation measure poss ble. Relief wells may be preferred response method in some well control events (shallow gas, compromised surface casing or surface casing cementing, broaching, etc.), but these events are highly unlikely to result in the release of liquid hydrocarbons.
COST: The cost to the applicant of achieving BAT, including consideration of that cost relative to the remaining years of service of the technology in use by the applicant	Fit-for-purpose equipment is already owned or under long-term contract. Well capping requires the maintenance of open-end contracts with trained specialists to implement well control/capping operations.	Time and cost of permitting, location construction, well planning and executing relief wells is estimated at 2 to 3 times the cost of well capping, excluding any lost production.
AGE AND CONDITION: The age and condition of technology in use by the applicant	Well capping technology has made improvements since its frequent application during the Iraq-Kuwait conflict in the early 1990s. Firefighting equipment is in place on the North Slope.	Relief well drilling technology is similar to current methods used to drill and complete North Slope wells. Potentially sensitive to blowout well types (extended reach drilling) and location.

TABLE 4-1 (CONTINUED): BEST AVAILABLE TECHNOLOGY ANALYSIS WELL BLOWOUT SOURCE CONTROL

BAT EVALUATION CRITERIA	EXISTING METHOD: WELL CAPPING	ALTERNATE METHOD: RELIEF WELL DRILLING
COMPATIBILITY: Whether each technology is compatible with existing operations and technologies in use by the applicant	Technology is compatible and applied at surface (no sensitivity to well type).	Technology is compatible though potentially sensitive to blowout well types (extended reach drilling, remote locations, etc.). Survey uncertainty on high departure wells may result in problems intersecting target wellbore.
FEASIBILITY: The practical feasibility of each technology in terms of engineering and other operational aspects	Method is feasible with all drilling operations. Applied at surface – no sensitivities to well type (extended reach drilling, remote locations, etc.). Prior proven success in offshore environments. Demonstrated success in historical well control efforts.	Method feasibility contingent upon geographical access near area of blowout. Lack of year-round access to some locations (offshore Beaufort) limits application. Very little evidence of successful application of relief well drilling as the primary mitigation measure of control. Relief wells may be preferred response method in some well control events (shallow gas, compromised surf casing or surf casing cementing, broaching, etc.), but these events are highly unlikely to result in the release of liquid hydrocarbons.
ENVIRONMENTAL IMPACTS: Whether other environmental impacts of each technology, such as air, land, water pollution, and energy requirements, offset any anticipated environmental benefits	Technology provides the best-proven opportunity to quickly reduce environmental impacts. Estimated duration is significantly less than conventional alternative technologies. Impacted area is localized to the affected well site and surrounding area.	Technology provides additional exposure and environmental risks during application (additional well control problems). Technology application may be seasonally limited, leading to durations of 60 to 180 days. Relief wells may require additional gravel placement and mobilization or demobilization pressures on the local environment. Drilling a relief well is accompanied by the additional risk of a second well control event.

4.2.2 CRUDE OIL TRANSMISSION PIPELINE SOURCE CONTROL

The pipeline source control procedures, required by 18 AAC 75.425(e)(4)(A)(i) (b) (3), (b) (7)(F) [redacted]s. Additionally, the oil pipeline across the Putuligayuk River includes a manual valve on both sides of the river.

There are two technology options for the valves: automatic ball valves and automatic gate valves. Both valve options, when installed in new condition, are similar in terms of availability, transferability, cost, compatibility, and feasibility. In terms of effectiveness, ball valves typically have slightly faster closure times than gate valves. For Northstar, automatic ball valves (block and bleed type) are used. As required by 18 AAC 75.055(b), the flow of oil or product/gas can be completely stopped by these valves within one hour after a discharge has been detected. The valve closure time for these types of valves is usually on the order of 2 to 3 minutes. See Table 4-2.

TABLE 4-2: BEST AVAILABLE TECHNOLOGY ANALYSIS CRUDE OIL TRANSMISSION PIPELINE SOURCE CONTROL

BAT EVALUATION CRITERIA	(b) (3), (b) (7)(F) [redacted]
AVAILABILITY: Whether technology is best in use in other similar situations or is available for use by applicant	[redacted]
TRANSFERABILITY: Whether each technology is transferable to applicant's operations	[redacted]
EFFECTIVENESS: Whether there is a reasonable expectation each technology will provide increased spill prevention or other environmental benefits	[redacted]
COST: The cost to the applicant of achieving BAT, including consideration of that cost relative to the remaining years of service of the technology in use by the applicant	[redacted]
AGE AND CONDITION: The age and condition of technology in use by the applicant	[redacted]
COMPATIBILITY: Whether each technology is compatible with existing operations and technologies in use by the applicant	[redacted]
FEASIBILITY: The practical feasibility of each technology in terms of engineering and other operational aspects	[redacted]
ENVIRONMENTAL IMPACTS: Whether other environmental impacts of each technology, such as air, land, water pollution, and energy requirements, offset any anticipated environmental benefits	[redacted]

PHMSA 000109452

4.2.3 TANK SOURCE CONTROL

The tank source control BAT review is provided in Table 4-3. Source control procedures for purposes of this BAT analysis also relate to the emergency shutdown valves on the fill line for oil-containing tanks to prevent a catastrophic release. (b) (3), (b) (7)(F) [redacted]

- [redacted]
- [redacted]
- [redacted]

TABLE 4-3: BEST AVAILABLE TECHNOLOGY ANALYSIS TANK SOURCE CONTROL DIESEL STORAGE TANK, WELL CLEANOUT TANK, PRODUCED WATER TANK

BAT EVALUATION CRITERIA	(b) (3), (b) (7)(F) [redacted]
AVAILABILITY: Whether technology is best in use in other similar situations or is available for use by applicant	
TRANSFERABILITY: Whether each technology is transferable to applicant's operations	
EFFECTIVENESS: Whether there is a reasonable expectation each technology will provide increased spill prevention or other environmental benefits	
COST: The cost to the applicant of achieving BAT, including consideration of that cost relative to the remaining years of service of the technology in use by the applicant	
AGE AND CONDITION: The age and condition of the technology in use by the applicant	
COMPATIBILITY: Whether each technology is compatible with existing operations and technology in use by the applicant	
FEASIBILITY: The practical feasibility of each technology in terms of engineering and other operational aspects	
ENVIRONMENTAL IMPACTS: Whether other environmental impacts of each technology, such as air, land, water pollution and energy requirements, offset any anticipated environmental benefits	
OTHER:	

4.3 TRAJECTORY ANALYSIS AND FORECASTS [18 AAC 75.425 (e)(4)(A)(i)]

Trajectory analyses and forecasts are described in the ACS Technical Manual, Tactics T-1 to T-6 and L-11, which are incorporated here by reference.

In the event of a spill, trajectory models will be based on observed and modeled currents, wind speed and direction, and observed oil tracking data. Vector addition and trajectory modeling are used to forecast oil movement on a real-time basis.

Several research and development programs are improving industry's capability to track environmental conditions real time. An industry- and agency-funded program is developing the capability of measuring ocean current speed and direction using high frequency radar. In 2009, the data was available real-time via the internet (Weingartner, 2010).

Under certain conditions, satellite-based Synthetic Aperture Radar (SAR) could be used to track large slicks on water in very open ice cover (<4/10). The current generation of all-weather SAR satellites can resolve targets to 1 meter resolution or less independent of cloud cover or light conditions. Consequently, SAR can play a valuable role in mapping detailed ice conditions and directing marine resources safely and efficiently (Sørstrøm et al., 2010). Existing commercial GPR systems can be used from a low-flying helicopter to detect oil trapped under snow on the ice and to detect oil trapped under solid ice (Sørstrøm et al., 2010).

4.4 WILDLIFE CAPTURE, TREATMENT, AND RELEASE PROGRAMS [18 AAC 75.425(e)(4)(A)(i)]

Wildlife capture, treatment, and release programs are described in the ACS *Technical Manual*, Volume 1, Tactics W-1 to W-3, W-5, W-6 and L-11, which are incorporated here by reference. The wildlife protection strategies are based on the *Wildlife Protection Guidelines for Alaska* (Annex G of the Alaska Regional Response Team Unified Plan).

See Volume 2 (Prevention Plan) for BAT analyses pertaining to:

- Cathodic Protection for Field-Constructed Oil Storage Tanks (Section 4.5)
- Leak Detection System for Field-Constructed Oil Storage Tanks (Section 4.6)
- Liquid Level Determination for Oil Storage Tanks (Section 4.7)
- Maintenance Practices for Buried Facility Oil Piping (Section 4.8)
- Protective Coatings and Cathodic Protection for Facility Oil Piping (Section 4.9)
- Maintenance Practices for Buried Facility Oil Piping – Corrosion Surveys (Section 4.10)
- Leak Detection for Crude Oil Transmission Pipelines (Section 4.11)

PART 5. RESPONSE PLANNING STANDARD [18 AAC 75.425(e)(5)]

Calculations of the applicable response planning standards set out in 18 AAC 75.432, .434, and .436, including a detailed basis for the calculation reductions to be applied to the response planning standards, are presented below.

5.1 STORAGE TANK [18 AAC 75.432]

The adjusted RPS volume for the diesel storage tank, Tank T-S3-8202, is calculated below. The tank's double wall design and tertiary containment area is sufficient to contain 110 percent of the tank volume and prevent oil from reaching open water.

Prevention credits applied to the tank rupture scenario are as follows:

- 60 percent adjustment for secondary containment,
- 25 percent adjustment for liner under tank/double bottom,
- 5 percent prevention credit for instrumented on-line leak detection system, and
- 5 percent adjustment for drug and alcohol testing program.

(b) (7)(F), (b) (3)

[redacted]

5.2 WELL BLOWOUT [18 AAC 75.434]

The 34,425-barrel RPS volume for a production well blowout simulation is based on a discharge rate of 2,295 barrels of oil per day (bopd) for 15 days.

The daily discharge rate reflects the average annual daily production volume for the maximum oil producing well at Northstar in 2010, based on data available through the Alaska Oil and Gas Conservation Commission (AOGCC). At ADEC's direction, the RPS oil volume is not adjusted for portions that are predicted by S.L. Ross Environmental Research, Ltd., to remain aloft and not enter receiving environments of land and water surfaces.

5.3 CRUDE OIL TRANSMISSION PIPELINE [18 AAC 75.436]

The initial RPS volume is calculated using the equation from 18 AAC 75.436.

(b) (7)(F), (b) (3) [redacted]

Where,

L = pipeline length between automatic pumping or receiving station valves

H = pipeline hydraulic characteristics due to terrain profile

C = pipeline capacity in barrels per linear measure

FR = pipeline flow rate in barrels per time period

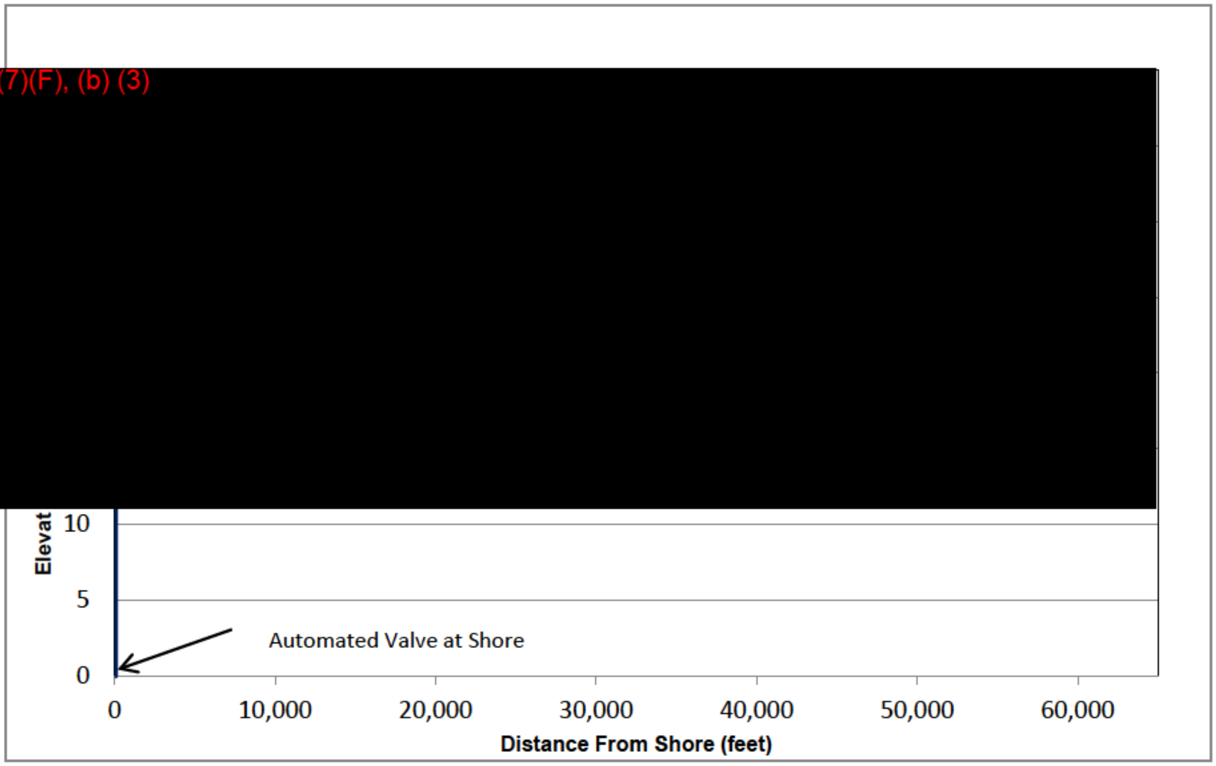
TD = estimated time to detect a spill event

TSD = time needed to shut down the pipeline pump or system

In the event of a catastrophic rupture, the board operator would immediately detect a change in pipeline operating pressures while simultaneously sensing a total loss of flow to Pump Station 1 (PS01) and no reduction in flow from the facility. The crude oil transmission pipeline (COTP) would be shut in immediately. Subsequent signal verification, shutdown support, and field verification would follow. For planning purposes, 45 minutes is assumed for detection and shutdown combined, although the period may be a few minutes.

(b) (7)(F), (b) (3) [redacted]

FIGURE 1-1: NORTHSTAR COTP ELEVATION PROFILE



(b) (3), (b) (7)(F)
[redacted]

Therefore,

(b) (7)(F), (b) (3)
[redacted]

Prevention credits applied to the crude oil transmission pipeline scenario are as follows:

- 5 percent prevention credit for drug and alcohol testing (discussed in Part 2),
- 5 percent prevention credit for on-line leak detection system (discussed in Parts 2 and 4), and
- 15 percent prevention credit for instrumented in-line cleaning and diagnostic equipment (discussed in Part 2).

(b) (7)(F), (b) (3)

[redacted]

FEDERAL

FACILITY RESPONSE PLANS

OPA 90 ADDENDUM

U.S. DEPARTMENT OF TRANSPORTATION
U.S. BUREAU OF SAFETY AND ENVIRONMENTAL ENFORCEMENT
U.S. COAST GUARD

U.S. DEPARTMENT OF TRANSPORTATION

NORTHSTAR
OIL DISCHARGE PREVENTION AND CONTINGENCY PLAN

CROSS REFERENCE TO
U.S. DEPARTMENT OF TRANSPORTATION RESPONSE PLAN REQUIREMENTS
[49 CFR 194, Subpart B]

REGULATION SECTION (49 CFR)	SECTION TITLE	OIL DISCHARGE PREVENTION AND CONTINGENCY PLAN SECTION (Page Number) (Volume 1 unless otherwise noted)
194.105	**Worst Case Discharge.**	
(a)	Each operator shall determine the worst case discharge for each of its response zones and provide the methodology, including calculations, used to arrive at the volume.	U.S. DOT Information Summary
194.107	**General Response Plan Requirements.**	
(a)	Each response plan must include procedures and a list of resources for responding, to the maximum extent practicable, to a worst case discharge and to a substantial threat of such a discharge.	Section 1.5: Deployment Strategies Section 1.6: Response Scenarios and Strategies Section 3.6: Response Equipment
(b)	An operator must certify in the response plan that it reviewed the NCP and each applicable ACP and that its response plan is consistent with the NCP and each applicable ACP as follows:	NCP/ACP Consistency Certification
(1)	As a minimum to be consistent with the NCP a facility response plan must:	
(i)	Demonstrate an operator's clear understanding of the function of the Federal response structure, including procedures to notify the National Response Center reflecting the relationship between the operator's response organization's role and the Federal On Scene Coordinator's role in pollution response;	Section 1.1: Emergency Action Checklist Section 1.2: Reporting and Notification Section 3.3: Command System
(ii)	Establish provisions to ensure the protection of safety at the response site; and	Section 1.3: Safety
(iii)	Identify the procedures to obtain any required Federal and State permissions for using alternative response strategies such as in-situ burning and dispersants as provided for in the applicable ACPs; and	BPXA does not consider the use of dispersants in this Facility Response Plan. Information for in-situ burning can be found in: Section 1.7: Non-Mechanical Response Options Section 3.7: Non-Mechanical Response Information
(2)	As a minimum, to be consistent with the applicable ACP the plan must:	
(i)	Address the removal of a worst case discharge and the mitigation or prevention of a substantial threat of a worst case discharge;	Section 1.6: Response Scenarios and Strategies Section 3.6: Response Equipment

REGULATION SECTION (49 CFR)	SECTION TITLE	OIL DISCHARGE PREVENTION AND CONTINGENCY PLAN SECTION (Page Number) (Volume 1 unless otherwise noted)
(ii)	Identify environmentally and economically sensitive areas;	Section 1.6: Response Scenarios and Strategies Section 3.10: Protection of Environmentally Sensitive Areas
(iii)	Describe the responsibilities of the operator and of Federal, State and local agencies in removing a discharge and in mitigating or preventing a substantial threat of a discharge; and	Volume 1 Section 1.1: Emergency Action Checklist Section 1.2: Reporting and Notification Section 3.3: Command System Section 1.6: Response Scenarios and Strategies Volume 2 Section 2.1.1: Training Programs Section 2.1.2: Substance Abuse Programs Section 2.1.3: Medical Monitoring Section 2.1.4: Security Programs Section 2.1.6: Operating Requirements for Exploration and Production Facilities Section 2.1.7: Leak Detection, Monitoring and Operating Requirements for Crude Oil Transmission Pipelines Section 2.1.10: Facility Oil Piping Section 2.3: Potential Discharge Analysis Section 2.4: Conditions Increasing Risk of Discharge Section 2.5: Discharge Detection
(iv)	Establish the procedures for obtaining an expedited decision on use of dispersants or other chemicals.	Not applicable.
(c)	Each response plan must include:	
(1)	A core plan consisting of -	
(i)	An information summary as required in 194.113,	U.S. DOT Information Summary
(ii)	Immediate notification procedures,	Section 1.2: Reporting and Notification
(iii)	Spill detection and mitigation procedures,	Volume 1 Section 1.6: Response Scenarios and Strategies Volume 2 Section 2.1.7: Leak Detection, Monitoring and Operating Requirements for Crude Oil Transmission Pipelines Section 2.4: Conditions Increasing Risk of Discharge Section 2.5: Discharge Detection
(iv)	The name, address, and telephone number of the oil spill response organization, if appropriate,	Table 1-3: BPXA Contact List
(v)	Response activities and response resources,	Section 1.6: Response Scenarios and Strategies

REGULATION SECTION (49 CFR)	SECTION TITLE	OIL DISCHARGE PREVENTION AND CONTINGENCY PLAN SECTION (Page Number) (Volume 1 unless otherwise noted)
(vi)	Names and telephone numbers of Federal, State and local agencies which the operator expects to have pollution control responsibilities or support,	Section 1.2: Reporting and Notification
(vii)	Training procedures,	Volume 1 Section 3.9: Training and Drills for Spill Response Personnel Volume 2 Section 2.1.1: Oil Discharge Prevention Training Programs
(viii)	Equipment testing,	Section 3.6.2: Maintenance and Inspection of Response Equipment
(ix)	Drill program- an operator will satisfy the requirement for a drill program by following the National Preparedness for Response Exercise Program (PREP) guidelines. An operator choosing not to follow PREP guidelines must have a drill program that is equivalent to PREP. The operator must describe the drill program in the response plan and OPS will determine if the program is equivalent to PREP.	Section 3.9: Training and Drills for Spill Response Personnel
(x)	Plan review and update procedures;	Introduction
(2)	An appendix for each response zone that includes the information required in paragraph (c)(1)(i)-(x) of this section and the worst case discharge calculations that are specific to that response zone. An operator submitting a response plan for a single response zone does not need to have a core plan and a response zone appendix. The operator of a single response zone on-shore pipeline shall have a single summary in the plan that contains the required information in 194.113.7; and	The Northstar Oil Discharge Prevention and Contingency Plan and this Facility Response Plan cover one response zone.
(3)	A description of the operator's response management system including the functional areas of finance, logistics, operations, planning, and command. The plan must demonstrate that the operator's response management system uses common terminology and has a manageable span of control, a clearly defined chain of command, and sufficient trained personnel to fill each position.	Figure 1-2: Northstar Incident Management Team Section 3.3: Command System Section 3.9: Training and Drills for Spill Response Personnel
194.109	**Submission of state response plans.**	
(b)	A plan submitted under this section must	
(1)	Have an information summary required by §194.113;	U.S. DOT information Summary

REGULATION SECTION (49 CFR)	SECTION TITLE	OIL DISCHARGE PREVENTION AND CONTINGENCY PLAN SECTION (Page Number) (Volume 1 unless otherwise noted)
(2)	List the names or titles and 24-hour telephone numbers of the qualified individual(s) and at least one alternate qualified individual(s); and	U.S. DOT Information Summary and Table 1-3: BPXA Contact List
(3)	Ensure through contract or other approved means the necessary private personnel and equipment to respond to a worst case discharge or a substantial threat of such a discharge.	Introduction: BPXA Statement of Contractual Terms with Alaska Clean Seas
194.113	**Information Summary.**	
(a)	The information summary for the core plan, required by 194.107, must include:	
(1)	The name and address of the operator; and	U.S. DOT Information Summary
(2)	For each response zone which contains one or more line sections that meet the criteria for determining significant and substantial harm as described in 194.103, a listing and description of the response zones, including county(s) and state(s).	U.S. DOT Information Summary
(b)	The information summary for the response zone appendix, required in 194.107…	Not applicable.
194.115	**Response resources.**	
(a)	Each operator shall identify and ensure, by contract or other approved means, the resources necessary to remove, to the maximum extent practicable, a worst case discharge and to mitigate or prevent a substantial threat of a worst case discharge.	Section 1.6: Response Scenarios and Strategies Section 3.6: Response Equipment Introduction: BPXA Statement of Contractual Terms with Alaska Clean Seas
(b)	An operator shall identify in the response plan the response resources which are available to respond within the time specified, after discovery of a worst case discharge, or to mitigate the substantial threat of such of such a discharge, as follows [12-60 hours].	Section 1.5: Deployment Strategies Section 1.6: Response Scenarios and Strategies Section 3.6: Response Equipment
194.117	**Training.**	
(a)	Each operator shall conduct training to ensure that:	
(1)	All personnel know-	
(i)	Their responsibilities under the response plan,	Volume 1 Section 3.9: Training and Drills for Spill Response Personnel Volume 2 Section 2.1.1: Oil Discharge Prevention Training Programs

REGULATION SECTION (49 CFR)	SECTION TITLE	OIL DISCHARGE PREVENTION AND CONTINGENCY PLAN SECTION (Page Number) (Volume 1 unless otherwise noted)
(ii)	The name and address of, and the procedure for contacting, the operator on a 24-hour basis, and	Section 1.1: Emergency Action Checklist Table 1-3: BPXA Contact List
(iii)	The name of, and procedures for contacting, the qualified individual on a 24-hour basis;	Section 1.1: Emergency Action Checklist Table 1-3: BPXA Contact List
(2)	Reporting personnel know-	
(i)	The content of the information summary of the response plan,	Volume 2 Section 2.1.1: Oil Discharge Prevention Training Programs
(ii)	The toll-free telephone number of the National Response Center, and	Section 1.2: Reporting and Notification
(iii)	The notification process; and	Section 1.2: Reporting and Notification
(3)	Personnel engaged in response activities know-	
(i)	The characteristics and hazards of the oil discharged,	Volume 1 Section 3.9: Training and Drills for Spill Response Personnel Volume 2 Section 2.1.1: Oil Discharge Prevention Training Programs
(ii)	The conditions that are likely to worsen emergencies, including the consequences of facility malfunctions or failures, and the appropriate corrective actions,	Volume 1 Section 3.9: Training and Drills for Spill Response Personnel Volume 2 Section 2.1.1: Oil Discharge Prevention Training Programs
(iii)	The steps necessary to control any accidental discharge of oil and to minimize the potential for fire, explosion, toxicity, or environmental damage, and	Volume 1 Section 1.1: Emergency Action Checklist Volume 2 Section 2.1.1: Oil Discharge Prevention Training Programs
(iv)	The proper firefighting procedures and use of equipment, fire suits, and breathing apparatus.	Volume 2 Section 2.1.1: Oil Discharge Prevention Training Programs
(b)	Each operator shall maintain a training record for each individual that has been trained as required by this section. These records must be maintained in the following manner as long as the individual is assigned duties under the response plan:	Volume 1 Section 3.9: Training and Drills for Spill Response Personnel Volume 2 Section 2.1.1: Oil Discharge Prevention Training Programs

REGULATION SECTION (49 CFR)	SECTION TITLE	OIL DISCHARGE PREVENTION AND CONTINGENCY PLAN SECTION (Page Number) (Volume 1 unless otherwise noted)
(1)	Records for operator personnel must be maintained at the operator's headquarters; and	Volume 1 Section 3.9: Training and Drills for Spill Response Personnel Volume 2 Section 2.1.1: Oil Discharge Prevention Training Programs
(2)	Records for personnel engaged in response, other than operator personnel, shall be maintained as determined by the operator.	Volume 1 Section 3.9: Training and Drills for Spill Response Personnel Volume 2 Section 2.1.1: Oil Discharge Prevention Training Programs
(c)	Nothing in this section relieves an operator from the responsibility to ensure that all response personnel are trained to meet the Occupational Safety and Health Administration (OSHA) standards for emergency response operations in 29 CFR 1910.120	Section 3.9: Training and Drills for Spill Response Personnel

Response Preparedness Certification

BP EXPLORATION (ALASKA) INC.
NORTHSTAR SALES OIL PIPELINE

Pipeline and Hazardous Materials Safety Administration
U.S. Department of Transportation
400 Seventh Street, SW, Room 2103
Washington, DC 20590

BP Exploration (Alaska) Inc. hereby certifies to the Pipeline and Hazardous Materials Safety Administration of the U.S. Department of Transportation that it has identified, and ensured by contract or other means to be approved by the Pipeline and Hazardous Materials Safety Administration, the availability of private personnel and equipment to respond, to the maximum extent practicable, to a worst case discharge or a substantial threat of such a discharge.

Terry Welch
Terry Welch
VP Operations
BP Exploration (Alaska) Inc.

10/27/14
Date

This certification of response preparedness was acknowledged before me on Oct. 27, 2014, by Terry Welch on behalf of said corporation.

DENISE M. BERRY
NOTARY PUBLIC
STATE OF ALASKA

Denise M Berry

10-13-2018
Date commission expires

NCP / ACP Consistency Certification

BP EXPLORATION (ALASKA) INC.
NORTHSTAR SALES OIL PIPELINE

BP Exploration (Alaska) Inc. hereby certifies to the Pipeline and Hazardous Materials Safety Administration of the U.S. Department of Transportation that it has reviewed the National Contingency Plan (NCP) developed under 40 CFR 300 and the applicable Area Contingency Plans, i.e. The Alaska Federal and State Preparedness Plan for Response to Oil and Hazardous Substance Discharges and Releases (Unified Plan) and the North Slope Subarea Contingency Plan. The Northstar Oil Discharge Prevention and Contingency Plan is found to be consistent with them.

Terry Welch
Terry Welch
VP Operations
BP Exploration (Alaska) Inc.

10/27/14
Date

U.S. DOT INFORMATION SUMMARY

Name and Address of Operator

BP Exploration (Alaska) Inc.
P.O. Box 196612
Anchorage, AK 99519-6612
Phone: (907) 564-5111

Street Address:
900 East Benson Boulevard
Anchorage, AK 99508
Fax: (907) 564-5180

Response Zone & Line Sections

The Northstar Unit is a single response zone with offshore and onshore pipelines including the Northstar Sales Oil Pipeline. This 10" crude oil pipeline originates at the Northstar Production facility which is located 5.968 miles offshore in the Beaufort Sea and ties into Pump Station 1 of the Trans-Alaska Pipeline System in the North Slope Borough of Alaska. The pipeline is approximately 17 miles long and consists of both offshore/subsea and onshore/aboveground portions.

Automatic shutdown valves are located on Northstar Island, the Pt. Storkersen shore crossing and at Pump Station 1. Manual shutdown valves are located on each side of the Putuligayak River (see Figures B-1, B-2 and B-4 in Volume 2 of the Northstar Oil Discharge Prevention and Contingency Plan [ODPCP] for further details).

Names and Telephone Numbers of Qualified Individuals

Name	Position	Telephone Number
Ed Wieliczkiewicz	NS Crisis Management Emergency Response Coordinator	(907) 659-4106
Ken Uftkin	NS Crisis Management Emergency Response Coordinator	(907) 659-4106

Additional contact information for BPXA personnel can be found in Table 1-3: BPXA Contact List in the Northstar ODPCP (Volume 1).

Basis for Determination of Significant and Substantial Harm

The onshore portion of the pipeline is expected to pose significant and substantial harm in the event of an oil spill as it is located in close proximity to environmentally sensitive areas.

Worst Case Discharge

In accordance with 49 CFR 194.105(b)(1), the worst case discharge (WCD) for the pipeline is equal to the pipeline's maximum release time (RT_{max}) in hours plus the maximum shutdown response time (ST_{max}) in hours multiplied by the maximum flow rate (F_{max}) expressed in barrels (bbl) per hour (bph) plus the largest pipeline drainage volume (PV_{max}) after shutdown of the line section(s) in the response zone expressed in bbl or:

$$WCD = [(RT_{max} + ST_{max}) * F_{max}] + PV_{max}$$

Where:

(b) (7)(F), (b) (3)

[redacted]

None of BPXA's historical discharges (as noted in Volume 2, Appendix C) exceed the above calculated WCD and BPXA does not maintain any breakout tanks between the Defense Early Warning Site and Pump Station 1. Therefore, historical discharges and breakout tanks were not included in the above WCD calculation.

Certification of Response Personnel and Equipment

Sufficient response personnel and equipment are available to respond to a WCD or threat of such a discharge. This information is provided in Sections: 1.6: Response Scenarios and Strategies; 3.5: Logistical Support; 3.6: Response Equipment; and, 3.8: Response Contractor Information (Volume 1 of the Northstar ODPCP).

U.S. BUREAU OF SAFETY AND ENVIRONMENTAL ENFORCEMENT

NORTHSTAR OPERATIONS
OIL DISCHARGE PREVENTION AND CONTINGENCY PLAN

CROSS REFERENCE TO
U.S. BUREAU OF SAFETY AND ENVIRONMENTAL ENFORCEMENT
RESPONSE PLAN REQUIREMENTS
[30 CFR 254, SUBPART D)]

REGULATION SECTION (30 CFR)	SECTION TITLE	PLAN SECTION
254.53	**Submitting a Response Plan Developed Under State Requirements**	Contents are in Volume 1 (Response Action Plan), unless otherwise specified
(a)(1)	Be consistent with the requirements of the National Contingency Plan and appropriate Area Contingency Plan(s).	Management Approval and Resource Commitment Statement, page i
(a)(2)	Identify a qualified individual and require immediate communication between that person and appropriate Federal officials and response personnel if there is a spill.	Sections 1.1, 1.2.4 and 3.3; Table 1-3
(a)(3)	Identify any private personnel and equipment necessary to remove, to the maximum extent practicable, a worst-case discharge as defined in §254.47. The plan must provide proof of contractual services or other evidence of a contractual agreement with any OSROs or spill management team members who are not employees of the owner or operator.	Introduction – Alaska Clean Seas Statement of Contractual Terms, Sections 1.2, 3.6 and 3.8, Facility Response Plan (OPA 90) Addendum
(a)(4)	Describe the training, equipment, testing, periodic unannounced drills and response actions of personnel at the facility to ensure both the safety of the facility and the mitigation or prevention of a discharge or the substantial threat of a discharge.	Section 3.9
(a)(5)	Describe the procedures to periodically update and resubmit the plan for approval of each significant change.	Introduction
(b)(1)	A list of facilities and leases the plan covers and a map showing their location.	This Appendix and Volume 2: Prevention Plan (Part 3.1 and Appendix B Figures)
(b)(2)	A list of the types of oils handled, stored, or transported at the facility.	Volume 2 (Prevention Plan) Section 3.1, Table 3-1, Appendix A
(b)(3)	Name and address of the State agency to which the plan was submitted.	Introduction – ADEC approval letter
(b)(4)	The date the plan was submitted to the State.	Introduction – ADEC approval letter
(b)(5)	If the plan received formal approval, the name of the approving organization, the date of approval, and a copy of the State agency's approval letter, if issued.	Introduction – ADEC approval letter
(b)(6)	Identification of any regulation or standards used in preparing the plan.	Introduction

REGULATION SECTION (30 CFR)	SECTION TITLE	PLAN SECTION
254.54	**Spill Prevention for Facilities Located in State Waters Seaward of the Coast Line**	
	In addition to your response plan, you must submit to the Regional Supervisor a description of the steps you are taking to prevent spills of oil or mitigate a substantial threat of such a discharge. You must identify all State or Federal safety or pollution prevention requirements that apply to the prevention of oil spills from your facility, and demonstrate your compliance with these requirements. You also should include a description of industry safety and pollution prevention standards your facility meets. The Regional Supervisor may prescribe additional equipment or procedures for spill prevention if it is determined that your efforts to prevent spills do not reflect good industry practices.	Volume 2, Prevention Plan

Ownership and Leases

The ownership breakdown for Northstar is as follows:

- BP Exploration (Alaska), Inc. 98.08 %
- Murphy Oil 1.92 %

Information on Northstar's facilities and leases with a map showing their locations can be found in this Appendix and the Northstar ODPCP Volume 2: Prevention Plan (Part 3.1 and Appendix B).

Federal Leases:

- 0179
- 0181
- 1645

More information on the federal leases can be found at:
http://www.boem.gov/Oil-and-Gas-Energy-Program/Mapping-and-Data/Alaska.aspx

State Leases:

- ADL 312798
- ADL 312799
- ADL 312808
- ADL 312809

More information on the state leases can be found at:
http://dog.dnr.alaska.gov/Publications/NorthSlope.htm#nsmaps
http://dog.dnr.alaska.gov/GIS/ActivityMaps.htm#resource

Worst-Case Discharge Volume

SOURCE	CAPACITY (BBL)	REFERENCE
Sum of Capacity of Oil Storage Tanks	(b) (7)(F), (b) (3) [redacted]	[redacted]
Capacity of Flow Lines	[redacted]	[redacted]
Crude Oil Transmission Pipeline Break	[redacted]	[redacted]
Daily Production Volume of Highest Capacity Well	[redacted]	[redacted]
Total	[redacted]	[redacted]

Worst Case Discharge Response Scenario

The following scenario discusses a simulated response to a worst case discharge (WCD), including adverse weather conditions. The following WCD scenario is developed in accordance with 30 CFR 254.26. Table 1 summarizes how the scenario meets the BSEE regulatory requirement. The table also provides references to documents that support the assumptions. The scenario is based upon assumptions about environmental conditions, oil distribution and response capabilities. The assumptions are supported by a number of publicly available technical documents.

The scenario describes equipment, personnel, and strategies that could be used to respond to an oil spill. The scenario is for illustration only. It is not a performance standard or a guarantee of performance. The scenario assumes conditions of the spill and responses only for the purpose of describing general procedures, strategies, and selected operational capacities.

Some details are examples. Although some equipment is named, it may be replaced by functionally similar equipment. The response timelines are for illustration only. They do not limit the discretion of the persons in charge of the spill response to select any sequence or take whatever time they deem necessary for an effective response without jeopardizing safety.

Actual responses are determined by the Unified Command, and depend on safety considerations, weather, and other environmental conditions, agency permits, response priorities, and other factors. In any incident, consideration for personnel safety is the highest priority. The scenario assumes the agency on-scene coordinators and other agency officials immediately grant permits.

Larger responses than illustrated in the scenario can be mounted with additional in-region resources and with the mobilization of out-of-region resources.

THIS PAGE INTENTIONALLY LEFT BLANK

WORST CASE DISCHARGE SCENARIO

WELL BLOWOUT DURING TYPICAL SPRING CONDITIONS

THIS PAGE INTENTIONALLY LEFT BLANK

TABLE 1: SUMMARY OF HOW THE SCENARIO COMPLIES WITH BSEE REGULATION

BSEE REGULATION	SUMMARY	REFERENCE
30 CFR 254.26(a) and 254.47(a) Worst Case Discharge Volume for Production Facility	(b) (7)(F), (b) (3) [redacted]	See the Oil Pollution Act of 1990 (OPA 90) BSEE cross reference section in Appendix A of the *Northstar Operations Oil Discharge Prevention and Contingency Plan* for descriptions of the basis of the WCD estimate. The estimates follow 30 CFR 254.47 regarding WCDs for production facilities. The total capacity of the oil storage tanks is the sum of permanent oil storage containers on Northstar Island. Flow line capacity specific to Northstar is calculated by the BPXA drilling development engineer. Northstar flow line capacity represents the sum of volumes from the production header, test header, sixteen production well lines, and the section of the sales oil line leading from the process facility to the island perimeter. Catastrophic release volume from the subsea portion of the sales oil pipeline is the sum of: 1) oil volume in the sales pipeline from Seal Island to the mainland landfall at Point Storkersen; and 2) an estimate of additional oil volume that would enter the pipeline from the production facility in the period before the break is detected and the valves shut. Calculation is consistent with 18 AAC 75.436, which takes into account length, flow capacity, leak detection and shutdown time, and the effects of hydraulic characteristics due to the terrain profile and gravity. The simulated blowout rate is based on the reservoir characteristics (as defined by BSEE).
30 CFR 254.26(b) Oil Trajectory	The simulation of the aerial oil plume is based on gas flow rate, orifice area, oil combustion, and wind direction. The frequency distr bution of the oil droplet size assumed in Tactic T-6 is assumed to remain unaffected by combustion or impingement. The simulation of 90 percent consumption of the oil during combustion of the aerial plume is based on the percentage burn efficiency as a function of the oil's flow rate, the gas-to-oil ratio, and the orifice diameter that is illustrated in SL Ross and Energetex (1986: Figure 11).	The oil's aerial plume trajectory is determined from ACS *Technical Manual*, Tactic T-6, a model developed by S. L. Ross Environmental Research, Ltd. (1997), and incorporated into the scenario by reference. The ACS *Technical Manual* parts that are cited in the scenario are thereby incorporated by reference. For a discussion of the expected proportion of oil consumed by combustion, see SL Ross Environmental Research Ltd. and Energetex Engineering (1986).

TABLE 1 (CONTINUED): SUMMARY OF HOW THE SCENARIO COMPLIES WITH BSEE REGULATION

BSEE REGULATION	SUMMARY	REFERENCE
30 CFR 254.26(b) Oil Trajectory (Continued)	The scenario assumes that oil droplets and gas affected by the well fire still form an aerial plume as large as predicted by the Tactic T-6 model for an un-ignited plume. The assumptions are made because no alternative model is available that accounts for reduction of the oil footprint by combustion of the aerial oil plume. The scenario assumes that the oil blows out to the atmosphere from a production well. In such a blowout, oil impingement on the well blowout preventer is expected to reduce the oil's aerial plume and reduce its footprint beyond the well. However, available models do not account for the affect of impingement on the oil footprint dimensions. Consequently, the scenario calculates oil footprints by the Tactic T-6 model for an un-obstructed plume.	The oil's trajectory on the sea is based on the following: 1. Historical water and ice movements in July are incorporated from Appendix H in SL Ross Environmental Research, Ltd., D.F. Dickins and Associates, Ltd. and Vaudrey and Associates, Inc. (1998). 2. Wind direction is simulated as prescribed by 18 AAC 75.425(e)(1). The wind data were retrieved from the Nearshore Beaufort Sea Meteorological Monitoring and Data Synthesis (Veltkamp, B. and Wilcox, 2007). The weather data presented were collected during the summers of 2000 through 2006.
30 CFR 254.26(c) Important Resources	Resources of special economic or environmental importance that potentially could be impacted are all the marine bird and mammal populations that occupy the sea between the pack ice and the shoreline and the shorelines of the barrier islands that lie in the oil trajectory. The trajectory is described in the body of the scenario. The resources are described more fully in the references.	Resources of special economic or environmental importance that potentially could be impacted in the areas in the trajectory are described in the ARRT's "North Slope Subarea Plan," Areas of Concern, which is also printed in the ACS *Technical Manual*, Volume 2, Map Atlas.
30 CFR 254.26(d)(1) Response Equipment	The scenario identifies the types, numbers and usage of the equipment capable of containing and removing the oil.	The equipment's types, locations, owners, inventory quantity and capabilities are descr bed in ACS *Technical Manual,* Volume 1, Tactics L-4 and L-6.
30 CFR 254.44(a) Effective Daily Recovery Capacities	The recovery rate for this scenario is assumed to be 20% of the pump's throughput rate. Based on the pump's throughput capacity of 1,181 boph, the de-rated recovery rate for this skimmer is 236 boph (20% x 1,191 boph = 236 boph).	
30 CFR 254.44(b) Other Efficiency Factors	The effective recovery capacity of the Foxtail rope mop skimmer is 75 barrels per hour, as determined by tests.	The recovery capacity for the Foxtail skimmer is 30 percent of the manufacturer's nameplate pump capacity (Canadian Association of Petroleum Producers Technical Report 92-01, 1992).
30 CFR 254.45(b) Other Efficiency Factors	The Crucial fiber-coated disc skimmer has been tested in conditions simulating its use in a break-up or freeze-up situation in Arctic conditions. The presence of ice in the test slick did not affect the performance of the skimmer, except to block the flow oil to the discs, lessening the overall recovery rate.	Section 1.6.2 of this plan and SL Ross test report (2010).

TABLE 1 (CONTINUED): SUMMARY OF HOW THE SCENARIO COMPLIES WITH BSEE REGULATION

BSEE REGULATION	SUMMARY	REFERENCE
30 CFR 254.26(d)(2) Deployment and Operation	The quantities and types of field personnel, materials and support vessels to deploy and operate the response oil removal and storage equipment are described in the "Discussion of Equipment, Personnel and Times" section of the scenario.	The locations and owners of the equipment are described in ACS *Technical Manual*, Volume 1, Tactics L-4 and L-6.
30 CFR 254.26(d)(3) Oil Storage, Transfer and Disposal	The oil storage, transfer and disposal equipment, including barges and oil processing facilities, is described in the scenario.	The types, locations, owner, quantity and capacity of the scenario's equipment are described in ACS *Technical Manual*, Volume 1, Tactics L-4 and L-6, Section 1.6.3, Temporary Storage and Disposal.
30 CFR 254.26(d)(4)(i) Time for Procurement of Oil Containment, Recovery and Storage Equipment	Mobilization (i.e., procurement) and transit time is reflected in the scenario.	Mobilization time for equipment is specified in equipment tables in the ACS *Technical Manual tactics* that the scenario incorporates by reference. In addition, BPXA has the capability to mobilize out-of-region resources, if needed. See Tactics L-8, L-9 and L-10.
30 CFR 254.26(d)(4)(ii) Time for Procurement of Transportation Vessels	Mobilization (i.e., procurement) and transit time is reflected in the scenario.	Mobilization time for vessels is specified in the ACS *Technical Manual* tactics that the scenario incorporates by reference.
30 CFR 254.26(d)(4)(iii) Time for Procurement of Personnel	Mobilization (i.e., procurement) and transit time is reflected in the scenario.	Mobilization time for staff operating vessels and other equipment is specified in the ACS *Technical Manual* tactics equipment tables that list equipment mobilization times. Equipment operators and crews mobilize with their equipment from North Slope origins through ACS contracts and mutual aid agreements; See Tactics L-8, L-9 and L-10 for mutual aid agreements, master agreements and other agreements for accessing equipment.
30 CFR 254.26(d)(4)(iv) Equipment Loadout Time	The times to transfer equipment to the transportation vessels are reflected in the scenario. The times are included in the mobilization times listed in the ACS *Technical Manual* tactics' equipment tables that the scenario incorporates by reference.	Equipment loadout time is included in the mobilization times specified for equipment and vessels listed in the ACS *Technical Manual* tactics that the scenario incorporates by reference.
30 CFR 254.26(d)(4)(v) Travel Time	Times to travel to the deployment site, including from equipment storage are described in the narrative of the scenario.	ACS *Technical Manual*, Tactic L-3 lists travel rates.
30 CFR 254.26(d)(4)(vi) Deployment Time	Times to deploy equipment are described in the scenario narrative and incorporated by reference to particular ACS *Technical Manual* tactics that list deployment times.	Deployment times for most equipment are specified in the ACS *Technical Manual* tactics equipment tables that list equipment deployment times.

TABLE 1 (CONTINUED): SUMMARY OF HOW THE SCENARIO COMPLIES WITH BSEE REGULATION

BSEE REGULATION	SUMMARY	REFERENCE
30 CFR 254.26(e)(1) Equipment and Strategies are Suitable for Conditions	Response equipment illustrated in the scenario is suitable, within the limits of current technology, for the range of environmental conditions anticipated at the facility. The equipment available on the North Slope and selected for the simulated deployments is the "best available technology" for responding to oil well blowouts in the nearshore Beaufort Sea. For example, the barges, vessels, boom, skimmers, and oil-burning equipment in the scenario have been tested and selected as the most suitable for mechanical oil recovery and in situ burning in the fast ice, broken ice and open water conditions associated with the facility. Response strategies illustrated in the scenario are also suitable, within the limits of current technology, for the range of environmental conditions anticipated at the facility. The strategies of burning and mechanical recovery illustrated in the scenario reflect "best available technology" for the conditions. The strategies have been tested, exercised and selected as most suitable for the conditions.	See the following analyses and reports that indicate that the scenario's equipment and strategies are the most suitable: 1. Blowout response plans in Section 1.9 of this plan; 2. Results of field tests of vessels, boom, skimmers and barges in broken ice near Northstar (Bronson, M., 2000); 3. Mechanical recovery and in situ burning strategy analyses (S. L. Ross Environmental Research, Ltd. D.F. Dickins and Associates, Ltd., and Vaudrey and Associates, 1998); 4. Response strategies and ice considerations in Northstar area (D.F. Dickins Associates Ltd., Vaudrey and Associates Inc. and SL Ross Environmental Research Limited, 2000); 5. Access capabilities on rotting ice around Northstar (Coastal Frontiers Corporation, 2001).
30 CFR 254.26(e)(2) Standard Terms for Conditions and Equipment Capabilities	The scenario employs standardized, defined terms to define environmental conditions and response equipment. The terms in the scenarios are consistent with terms used in spill response planning in general and for North Slope responses in particular.	FOR DEFINITIONS OF TERMS SEE THE FOLLOWING DOCUMENTS: 1. D.F. Dickins Associates, Ltd., Vaudrey and Associates, Inc. and SL Ross Environmental Research Limited. 2000. *Oil Spills in Ice Discussion Paper: A Review of Spill Response, Ice Conditions, Oil Behavior, and Monitoring.* Prepared for Alaska Clean Seas. 2. Alaska Clean Seas, *Technical Manual*, Volume 1: Tactics Descriptions, and Volume 2: Map Atlas.

Simulated Weather and Sea Conditions at Spill Scene

The scenario reflects historical ice and weather conditions that are described in references cited in the last column of Table 1. The weather is typical of the season. Air temperatures average 35 degrees F and range from 20 to 40 degrees F. The wind is variable, but blows predominantly from the E and NE, averaging 10 knots.

Ice floe maximum diameters are 500 to 1,000 feet in the first two days of break-up. They diminish to 30 to 40 feet within three weeks. The wind pushes ice of 7 tenths to 9 tenths coverage at 1 to 2 percent of wind speed, concentrations of 4 tenths to 6 tenths at 2 to 3 percent of wind speed, and 3 tenths and less at 3 to 4.5 percent of wind speed. Ice moves 30 degrees to the right of the wind direction.

Table 2 illustrates sea and ice conditions.

TABLE 2: SIMULATED ICE CONDITIONS DURING BREAK-UP

DATES	WIND DIRECTION	WIND SPEED	SIMULATED CONDITIONS IN THE VICINITY OF NORTHSTAR PRODUCTION ISLAND
June 7	ENE	Averages 11 knots	The Kuparuk River overflood reaches within one mile of Northstar Island. Floodwaters drain through the ice within the overflood area (shore to the seaward boundary of the flood waters), leaving a relatively dry surface with scattered meltwater pools (Condition 6).
June 12	ENE	Averages 11 knots	The simulated blowout begins. Solid ice still surrounds Northstar Production Island. The ice is 4 feet thick. The surface is melting, with a soft surface and meltwater pools having 25 percent coverage (Condition 6).
June 15	ENE	Averages 11 knots	Gwydyr Bay ice melts in place and the lagoon becomes ice free. Offshore of the barrier islands, the overflood drains through the ice. June 15 is the last day that conventional wheeled vehicles travel the ice road between West Dock and the Northstar Production Island.
July 4	ENE	Averages 11 knots	Deteriorated fast ice (4-5 ft. thick) starts to shift and fracture. Most of the energy generated by the wind is spent fracturing the deteriorated ice sheet into large floes. Ice concentrations remain 9/10th all day and large floes (over 1,000 ft.) start to shift locally around the island (hundreds of feet). (Condition 7)
July 5	ENE	Averages 11 knots	Ice starts to open around the island with large floes moving past. Ice concentrations are 7-9/10th. Openings are small (less than a few hundred feet) and transient in time (tens of minutes). Dominant floe sizes range from 500 to 1000 ft.
July 6	ENE	Averages 11 knots	Ice concentrations in the 6-8/10th range, with floes moving past the island at about 0.3 knot (scattered openings in the cover up to 500 ft across and lasting for up to several hours). Dominant floe sizes in the range of 250 to 700 ft. During days 2 and 3 the ice moves approximately 10 nautical miles to W based on a drift rate of 2 percent of the wind and 30° to the right of the wind. A shoreline rubble pile forms against the east side of Northstar Island. (Condition 8)
July 7-9	ENE	Averages 11 knots	Ice concentrations of 4-6/10th wallow around the island. Ice distribution becoming patchy with a series of openings with less than 1/10th ice separated by more concentrated areas of ice (up to 7/10th). Spatial extent of the openings and the ice patches about equal. Dominant floe sizes range from 250-700 ft.
July 10-14	W	Averages 11 knots	Very patchy ice concentrations of 2-5/10th. Large areas (1-200 ft) of close to open water are interspersed with belts and patches of ice up to 6/10th. Floe size is in the range of 100-500 ft.
July 15	W	Averages 11 knots	Ice concentration of 3-5/10th. Slightly less patchy than previous five day period. Open areas are smaller (less than 1000 ft. across and more frequent). Floe size is in the range of 70-250 ft.
July 16-18	W	Averages 11 knots	Ice concentrations of 1-3/10th move sporadically in patches past the island. Stretches of open water for up to ½ mile separated by bands of patches of 6-7/10th ice several hundred feet across. Dominant floe sizes in the range of 50-150 ft.
July 19-22	W	Averages 11 knots	Trace to 1/10th distributed as strips and irregular patches of 6-7/10th ice up to hundred feet across, separated by areas of open water up to ¾ mile in extent. Dominant floe sizes in the 30-40 ft range. (Condition 9)

Note:

1. Per convention, the wind states the direction of wind origin (i.e., where the wind is coming from). The predominant wind directions during the simulated blowout were determined from the 16 cardinal compass directions that blow over 10 percent of the time. The wind data were retrieved from the Nearshore Beaufort Sea Meteorological Monitoring and Data Synthesis (Veltkamp and Wilcox, 2007). The data represented above was collected from 2004 through 2010.
2. Ice conditions are summarized from Dickins, D.F., K. Vaudrey, and SL Ross (2000).

October

Freeze-up begins October 10 and ice around the Northstar Production Island becomes completely fast (i.e., stable with movements less than 100 feet) for the season on November 15. Between October 10 and October 25, complete break-up of the young ice cover is possible in response to fall storms. From October 25 to November 15 large-scale break-up of the sheet is unlikely but movements up to thousands of feet can occur with strong winds. Air temperatures range from 5 to 15 degrees F. Daylight is 9 to 10 hours per day. Broken new ice at freeze-up moves at 4 to 4.5 percent of the wind speed and 30 degrees to the right of the wind direction.

<u>Characteristics of the Discharged Oil [30 CFR 254.26(a)]</u>

Oil from the Kuparuk Formation reaches the surface from a Northstar production well several hours after a kick is detected. Oil flows at the rate of approximately 2,762 bopd. The simulated blowout discharges a total of approximately 82,860 barrels of crude oil over 30 days, although only the unburned portion falls out to surfaces. See the vicinity map in Figure 1.

The scenario assumes that the blowout oil ignites at the well house floor on Day 1. Sub-surface safety valves prevent nearby production well blowouts in the case of collateral fire damage of the well trees. The effect of the ignition is to (1) increase safety by removal of toxic and flammable gases, (2) decrease pollution of the sea surface, and (3) increase the effort necessary to access the wellhead for well capping. Over the course of 30 days, a new capping stack is installed. The oil from the well burns without interruption until it is diverted with the capping stack as part of the kill step.

Ninety percent of the oil is lost to combustion when the aerial oil plume ignites (SL Ross Environmental Research Ltd., 1986). Oil from the ignited well impacts surfaces on the production island and the surrounding area at the rate of 249 bopd [2,762 bopd x 10 percent un-burned = 277 bopd x 90 percent in droplets large enough to settle = 249 bopd.] Over 30 days of the blowout, approximately 7,470 barrels fall to the surface of the production island and surrounding area.

Where the oil falls to water, it forms little or no emulsion (SL Ross Environmental Research Ltd., 2001).

The aerial oil follows trajectories dictated by wind direction and as predicted by the SL Ross plume dispersion model published in ACS *Technical Manual*, Tactic T-6. Adoption of the Tactic T-6 trajectories assumes that the length and width of the simulated aerial oil droplets plume remain unaffected by the loss of airborne oil to evaporation and combustion and the loss of gas by combustion. The aerial oil plume extends approximately 4.9 miles from the well. Each triangular footprint of oil settlement is 1,230 acres [(4.9 miles long x 0.67 miles wide X 0.5) x (640 acres per square mile) = 1,051 acres].

Approximately 13 percent of the falling oil (32 bopd) contacts the Northstar Production Island. Over 30 days, 960 barrels falls to the Northstar Island surface. The remainder of the discharged oil contacts ice and/or water surrounding the Northstar Production Island surface at a rate of 217 bopd [249 bopd falling oil x 87 percent falling to ice and/or water surrounding Northstar Production Island surface = 217 bopd]. Over 30 days, 6,510 barrels falls to surfaces beyond the island. See Figure 1.

Oil Spill Trajectory [30 CFR 254.26(b)]

Through Day 22, before break-up north of the barrier islands, movement of surface oil deposits is very limited. From June 12 to July 3, the oil falls out to the sea ice. See Figure 1 for examples of deposition zones.

From July 4 to 6, during aggressive break-up of the sea ice around Northstar, the oil falls out to large pieces of moving broken ice and to some water. By the end of July 6 (Day 25), the ice that had been fast to the island over the winter has moved 10 nautical miles WNW. Oil deposited to the sea ice and leads during the 3 days is carried with the ice [249 bopd x 3 days = 747 bbl].

From July 7 to the end of the blowout on July 11, the broken ice moves northward 5 to 7 miles as it becomes patchier and decreases in area coverage. Under the light southern winds, the oil moves in the same direction, but as far as 10 miles northward. A zone containing scattered oil becomes centered NW of the island. The area contains as much as 1,992 barrels [249 bopd x 8 days = 1,992 bbl] that was deposited between July 4 and July 11.

For several days immediately after the blowout stops, winds from the N move oil and ice southward to nearshore waters from Prudhoe Bay to Spy Island and Harrison Bay. The oil on water takes the form of windrows. Most of the remaining oil strands on scattered sections of shorelines, primarily on the barrier islands.

During the remaining 10 days of the broken ice period, to July 20, the remaining oil on ice and on water generally moves westward as scattered patches in a water corridor between the Beaufort Sea coast and the Arctic ice pack. Oil on the water is mainly windrows and sheen. The clockwise deflection of water and oil under the east wind tending to carry the oil offshore and the presence of barrier islands act together to minimize the potential for oil to enter the lagoons.

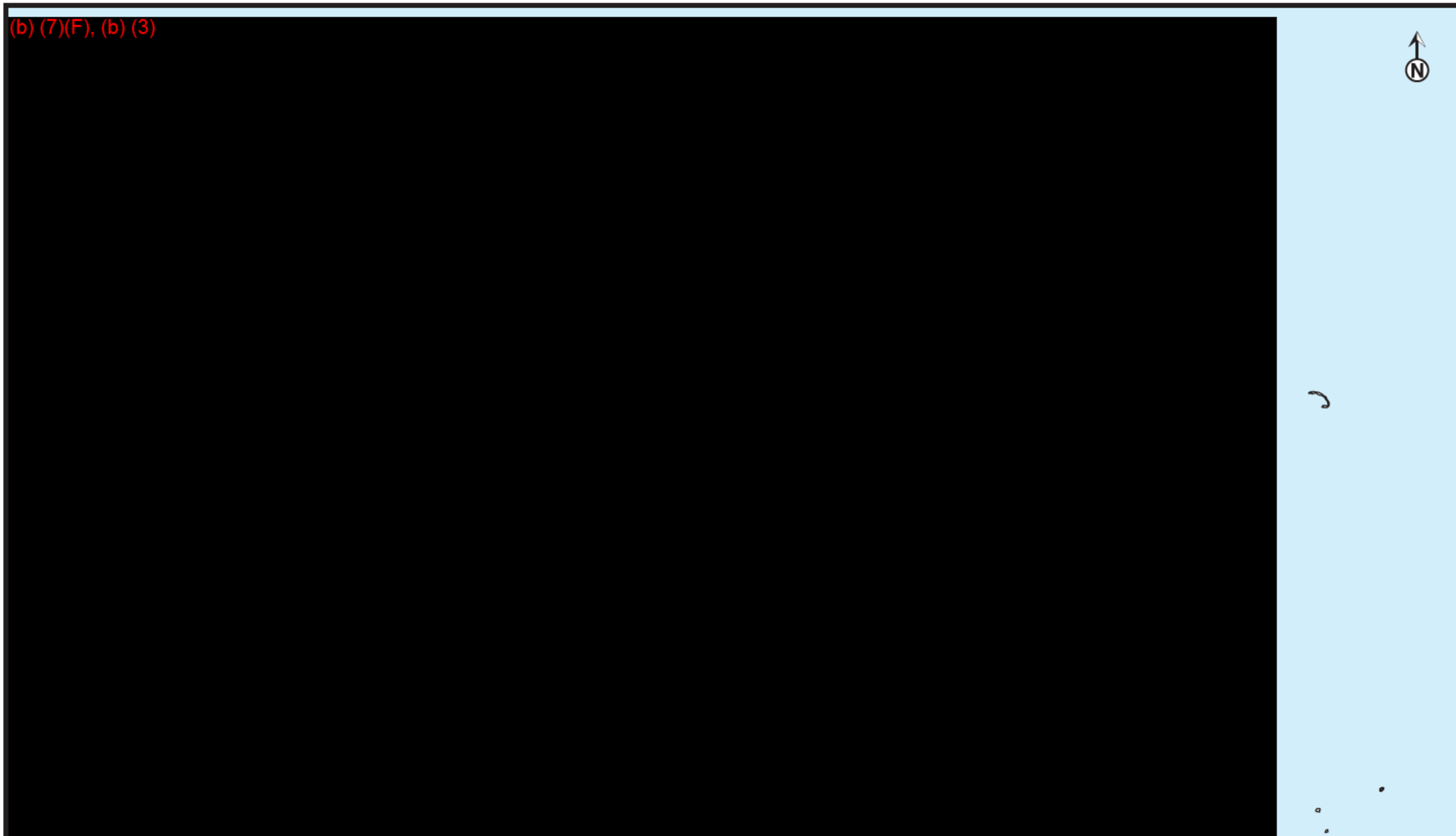
The floating oil that remains is no longer significantly affected by broken ice from late July until freeze-up in October. During the open water period, floating oil as windrows and sheen moves under the influence of currents with a net westward movement typical of the area. Some oil strands on shorelines and becomes entrapped in the Arctic ice pack.

The oil decreases in quantity and becomes distributed along shorelines and on water and ice in a pattern similar to that described in a 1,000-barrel summer spill scenario by the U.S. Army Corps of Engineers' Final Environmental Impact Statement for Northstar (1999), Table 3 and Figures 8-4b and 8-5b. Most simulated shoreline impact is on the outer shoreline of the barrier islands from Prudhoe Bay to Long Island. Most oil on the water and on sea ice extends from Prudhoe Bay to eastern Harrison Bay. Very little oil is found west of Spy Island.

Little floating oil remains when the nearshore Beaufort Sea begins to freeze into shorefast ice on October 10 and entraps the oil. The area experiences several cycles of fast ice formation under calm conditions and new-ice shattering under stronger, shifting winds.

(b) (7)(F), (b) (3)

[redacted]



[redacted]l Blowout
[redacted]al Spring
[redacted]icinity Map

Figure 1

Resources of Importance [30 CFR 254.26(c)]

Resources of special economic or environmental importance could be impacted by the spilled oil. Marine and coastal bird and mammal populations and shoreline cultural resources occupying the path of the spilled oil described in the Trajectory section potentially could be affected by oiling.

Many of the birds and mammals are important both ecologically and economically. The ACS *Technical Manual*, Volume 2, lists the marine mammal groups and marine bird groups potentially exposed to the scenario's oil, and describes their seasonal distribution in the spill vicinity. Threatened and endangered species protection notes are also provided in the *Technical Manual*'s map descriptions. In addition, the types of coastal habitats exposed to the oil are listed by level of concern and depicted on maps of the spill area. Catalogued cultural resource sites are listed on the maps that cover their vicinity in the spill area as well. The *Technical Manual* lists are adapted from the Alaska Regional Response Team's (ARRT's) "North Slope Subarea Plan."

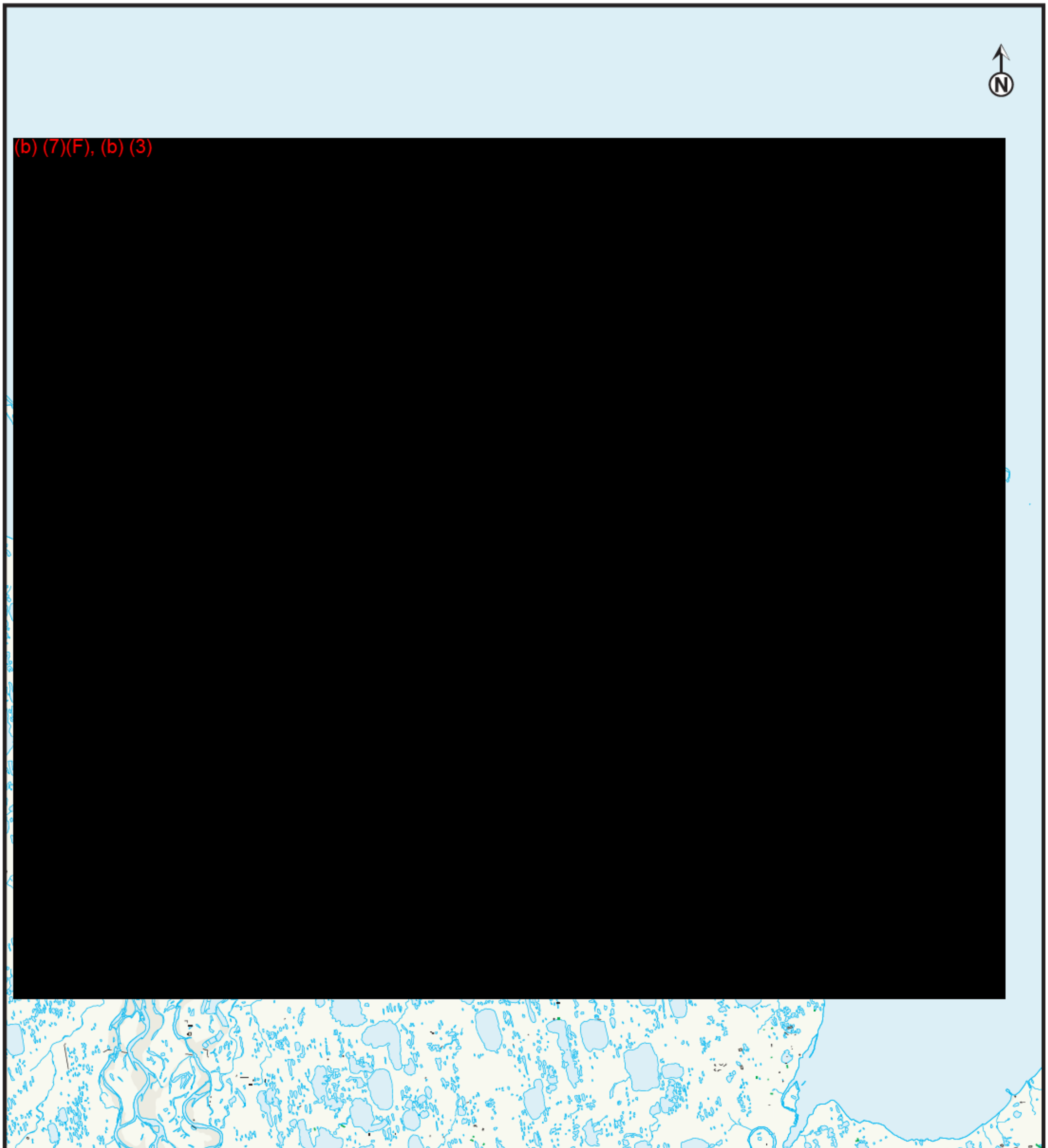
The first strategy to protect resources of importance is to remove oil quickly and where it still lies in thick layers close to the spill source. Targeting that area can most effectively reduce the quantity of oil available to move into sensitive areas later.

A further strategy is to deploy exclusion and deflection boom at selected shoreline sites. The sites are selected partly on their suitability for maintaining boom conformance and anchors in the face of wind, waves and current. See the priority protection sites marked in the ACS *Technical Manual*, Volume 2. Simulated oil trajectories are shown in Figure 2. ACS *Technical Manual* Map Atlas maps 30 to 34, 56, 58 to 60, 62, 65, 66, 92, and 93 show the shorelines near the simulated trajectories. Where pre-staged equipment has been placed on marine shorelines, the maps indicate its location and list the contents of the containers.

To protect shoreline sites from oncoming oil that escapes the offshore oil removal task forces, strike teams of workboats tow delta and harbor boom from West Dock and anchor it in shallow water. Exclusion booming and deflection booming tactics, including equipment lists, personnel numbers, procedures, and mobilization and deployment times, are described in ACS *Technical Manual* Tactics C-13, C-14, and C-15. The numbers and features of the vessels and boom are outlined in Tactic L-6.

To protect birds and mammals, the main strategy is removing oil from the environment. The primary strategy for direct wildlife protection is hazing and collection of oiled carcasses. In the early hours of the spill response, hazing is carried out with ACS equipment and trained personnel under the direction and permits of the ADFG and the USFWS. Oiled carcasses are collected to remove them as sources of injury to predators. Oiled animals are captured, stabilized and treated by specialists using ACS equipment, including the wildlife stabilization facility at Prudhoe Bay. Animals requiring further treatment are transported to the Alaska Wildlife Rehabilitation Center in Anchorage. See ACS *Technical Manual* Tactics W-1 to W-6 for decision-making and field procedures.

On the fast sea ice, seal breathing holes are identified and avoided by response operators under advisories from specialists in the Wildlife Unit.



[redacted]

Northstar Well Blowout
During Typical Spring
Conditions
Days 1 - 4 in June

	1" = Approx. 2.5 Miles	Figure 2

Discussion of Equipment, Personnel and Times [30 CFR 254.26(d)(1) through (4)]

The following discussion illustrates a response to a WCD scenario in adverse weather conditions. The adverse weather conditions involve low temperatures, high winds, periods of fog, short-period waves up to 3 feet and ice concentrations. Descriptions of conditions are provided in the Simulated Conditions section of the scenario and in ACS *Technical Manual*, Tactic L-7, Realistic Maximum Response Operating Limitations, for mechanical response equipment. In addition, skimmer capacities are de-rated to reflect the effects of adverse weather among other factors.

The locations, owner and capacities of response equipment, personnel, materials, support vessels, oil storage, transfer, and disposal equipment in the scenario are listed in the ACS *Technical Manual* tactics cited in the narrative. The cited ACS *Technical Manual* tactics are incorporated into the scenario by reference.

Mobilization (procurement) and deployment times of the scenario's containment and recovery, storage equipment, equipment transportation vessels, and personnel to load and operate the equipment are listed in the ACS *Technical Manual* tactics' equipment tables. Equipment loadout times to transfer equipment to vessels are incorporated into the mobilization times. The tables are incorporated into the scenario by reference.

In situ burning and oil recovery operations are conducted on two 12-hour shifts per day. The equipment operates for 10 hours in each 12-hour shift. The remaining 2 hours represent down-time when equipment is out of conformance or conditions are beyond the equipment's operating limitations.

June

Mobilization of oil containment and removal equipment begins on June 12, Day 1 of the simulated spill. The equipment is deployed at the spill scene and staged on the island in the first few days to avoid the surface transportation barrier posed by the loss of the ice road on June 15, Day 4 of the spill. Amphibious and tracked vehicles and airboats mobilized from North Slope sources provide stable work platforms and access to the ice. A staging area is set up at West Dock staging area on Days 1 and 2. See Tactics L-2 to L-6 and L-8 to L-10.

Equipment operations and workers on foot follow safety guidelines for vehicle load, ice thickness and ice condition and for walking on deteriorating ice that are found in Sandwell Engineering, Inc.'s (2001) Ice Access Guidelines for Spill Responders, prepared for ACS. ACS and SRT oil containment and removal crews work in safety zones determined by the Site Safety Officer, following OSHA standards. Containment and recovery operations are allowed without respiratory protection where safety criteria are met through real-time monitoring.

Some spill response workers operate closer to the blowout where oil particulate matter is expected to exceed the OSHA 8-hour PEL. The workers wear full-face air purifying respirator and organic vapor cartridges, chemically protective outwear over FRC, and nitrile gloves. The workers recover oil under all of the following conditions:

- Oxygen atmospheric concentration is between 19.5% and 23.5%

- LEL percentage is less than 3%
- Total hydrocarbon concentration is less than 500 ppm
- H_2S air concentration is less than 10 ppm
- Benzene air concentration is less than 10 ppm
- No visible mist or fog of oil present

Island

On Day 1, earth-moving equipment excavates a trench on the island bench to divert oil draining from the pad. A Challenger mobilizes from Prudhoe Bay to the island across the sea ice. Tracked Tucker trucks with blades also mobilize and travel on the same schedule.

Decontamination facilities are set up at West Dock during the initial hours of the response. A mobile decon site is mobilized from Prudhoe Bay and set up on the island bench on Days 2 and 3 during the last days of the ice road. On Day 4, a safe access work plan is implemented (Tactics S-1 to S-6).

Sea Ice

Oil spill response technicians and equipment operators mobilize on Day 1 with their equipment for work on the sea ice.

On Day 1, 500 feet of fireboom is mobilized from storage at West Dock, hauled by Rolligon, and deployed on the ice adjacent to the island to contain oil draining from the island (Tactics C-11 and B-4).

A trencher machine cuts shallow trenches in the sea ice near the island beginning on Day 1. The objective is to divert and concentrate oil into depressions.

On Day 1, the Unified Command determines that ice conditions exceed the operating limit of mechanical oil transfer equipment. The option of hauling oil to shore with wheeled dump trucks and tankers once the oil is collected in pits and snow mounds is precluded by the seasonal loss of the ice road. Consequently, the contained oil and oil mixed with ice is burned in situ.

On Day 2, the Challenger moves oiled snow several hundred feet from the island to create fire breaks. On the sea ice, the Challenger and tracked Tucker trucks with blades begin moving windrowed snow and excavated material into berms on Day 2 (Tactics C-4 and C-12). The berms divert oil into depressions and away from un-oiled areas.

From June 13 to June 30, oil is burned on the ice and on the water perched on the ice by surface crews. See Figure 3.

The burning teams each comprise two vehicles: a tracked vehicle with a blade to make mounds and berms, and an airboat to shuttle burn residue from the spill scene. During this period, assuming a mix of 70 percent of the oil in thick films with 95 percent burn efficiency, and 30 percent of the oil in thin films with a 70 percent burn efficiency, the overall percentage remaining as residue is estimated as 13 percent (1-(0.95*0.70)+(0.70*0.30) = 13). The teams engage in the following tactics:

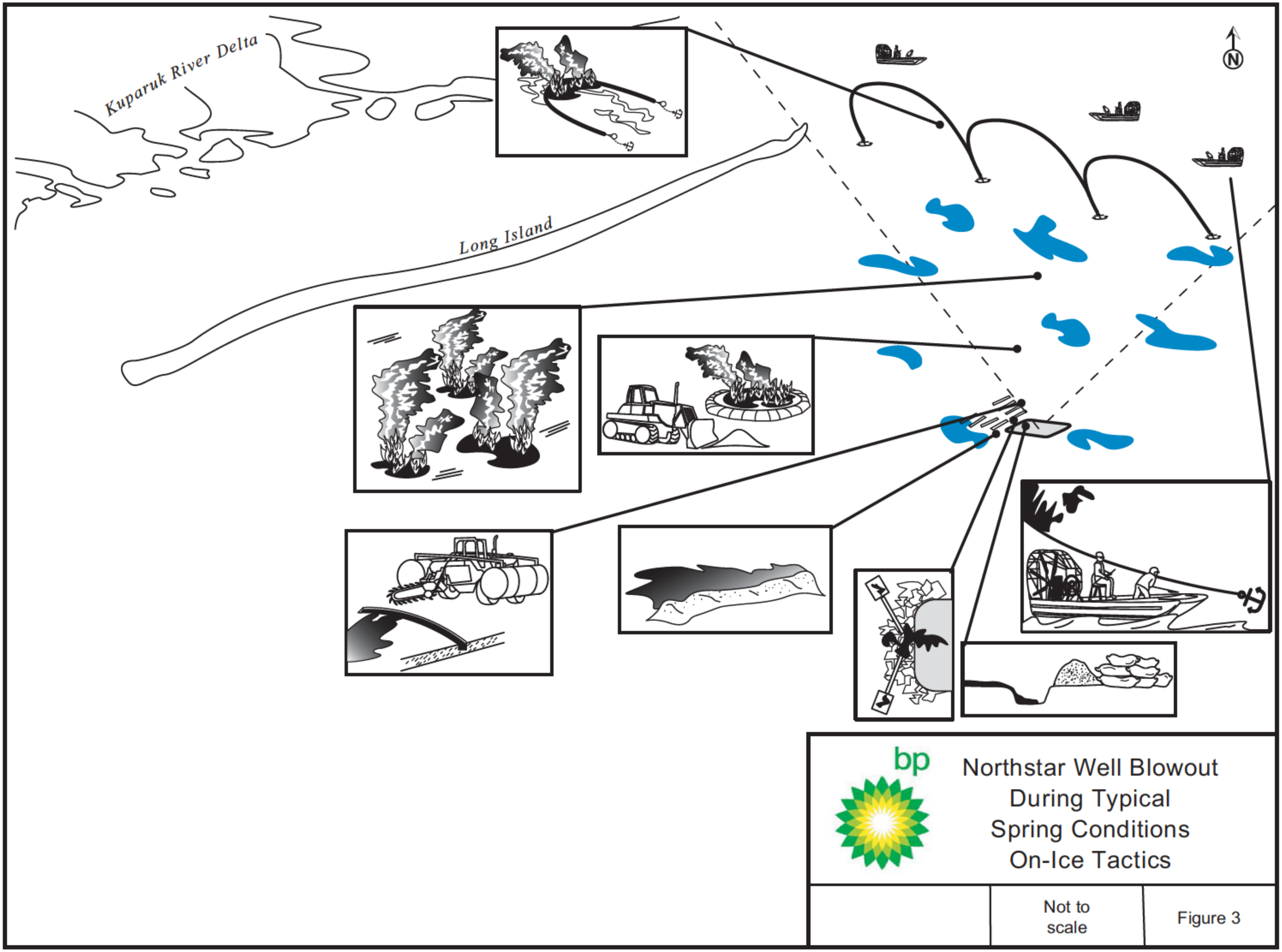
Mounds. Bladed vehicles move oiled snow into mounds for burning at a rate of 2 acres per day per vehicle (Tactic B-5). See the report by Coastal Frontiers Corp. 2001. Spring Break-Up Equipment Access Test Program, June 2001, for measured rates on deteriorating sea ice.

Depressions. The tracked Tucker truck vehicles also move snow into berms to divert and contain oil released from melting snow into thicker concentrations on meltwater pools for the purposes of burning and to exclude oil from un-oiled areas. See Tactics C-4, C-11, C-12, B-5, and B-6.

Fireboom. Oil pooled in trenches and behind fire booms near the island is ignited when the accumulation becomes thick, and the wind is away from the island and nearby on-ice operations (Tactic B-4).

Aerial Ignition. Oil on the ice naturally migrates to meltpools and accumulates against downwind ice edges. A helicopter drops gelled gasoline on more isolated pools of oil (Tactic B-3).

Residue is collected with hand tools as it becomes available for transfer and storage at the average rate of 6.7 cubic yards per day [(249 bopd x 13 percent residue) = 32.4 bopd; (5.6 cubic feet per bbl / 27 cubic feet per cubic yard) x (32.4 bopd) = 6.7 cubic yards per day] (Tactic B-6). Residue is transferred by an airboat with shuttling capacity exceeding the rate that residue becomes available. Volumes are measured in the containers and logged on manifests.


Kuparuk River Delta
Long Island
N
bp
Northstar Well Blowout
During Typical
Spring Conditions
On-Ice Tactics
Not to
scale
Figure 3

Melt Ponds

Beginning Day 2, a task force of airboats burns oil in the apices of fire boom on ponds of perched melt water and overflood water with handheld igniters (Tactic B-5). Fire booms are deployed and anchored in the ice. Airboats deploy boom and anchors and set up the configurations. A series of fire booms spans the oil plume. Each U-shaped fire boom has a sweep of approximately 300 feet and contains oil where it is burned in the boom apex. See Figure 4.

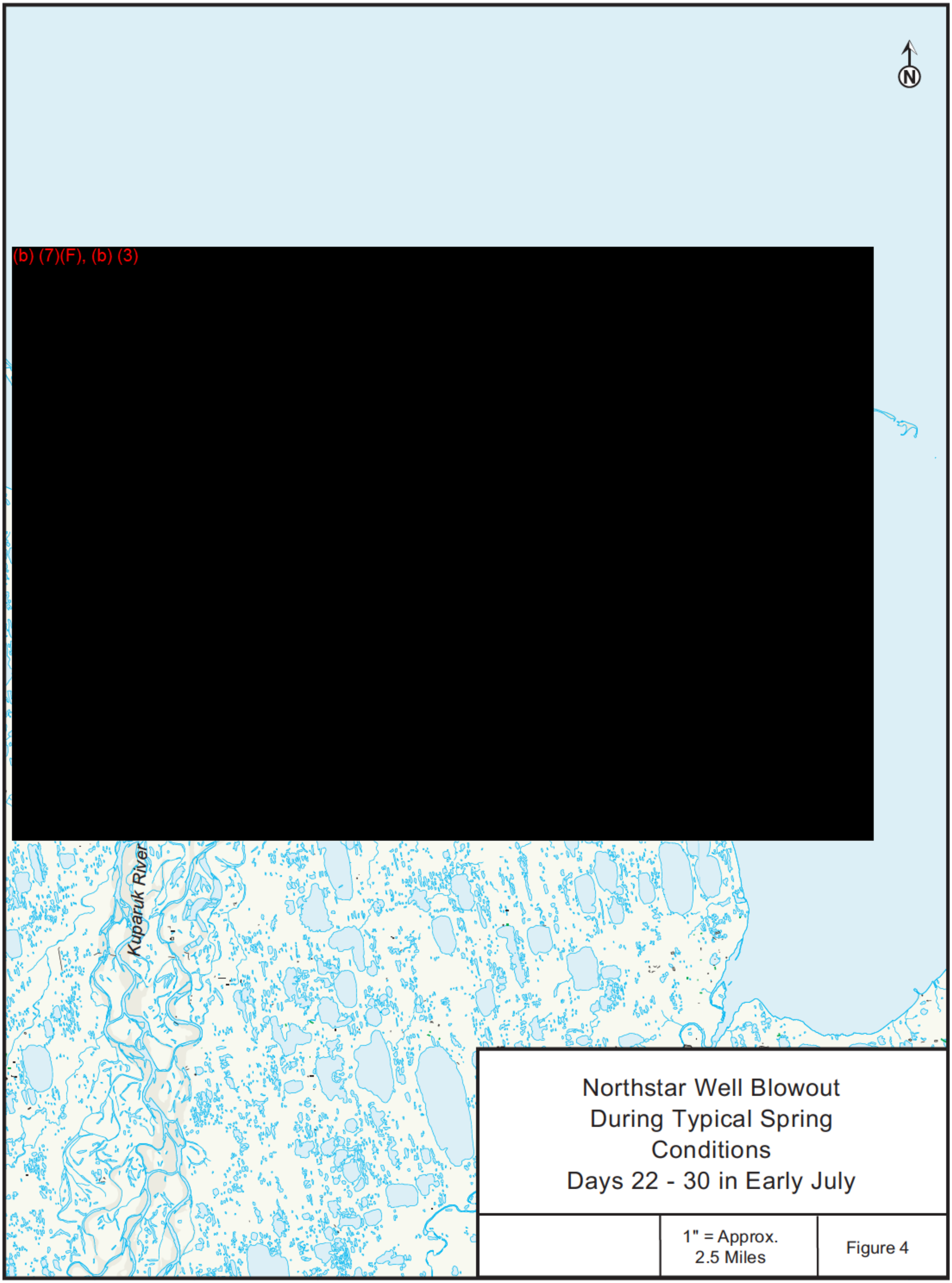
Figure 4 shows simulated response tactics Days 22 to 30 in early July. Table 3 and Table 4 list the major equipment and staff for oil removal before break-up.

<u>July 1 to 4</u>

On July 1, Unified Command halts the on-ice operations in anticipation of break up. Ice tracking beacons and buoys are deployed with the objective of tracking potentially remaining oil as the ice breaks up (Tactic T-4A). A helicopter with a heli-torch is dispatched daily to burn oil patches on ice and water (Tactic B-3).

TABLE 3: MAJOR OIL CONTAINMENT AND RECOVERY EQUIPMENT EQUIVALENTS NEEDED BEFORE BREAK-UP

TACTIC	EQUIPMENT	NO. ITEMS
On Island, Day 1		
C-4, Berms on Island	Backhoe	1
On Sea Ice, Day 1		
B-4, Fire Containment Boom	Fire Boom	500 feet
	Airboat	1
	Rolligon	1
C-11, Trenching on Ice	Ditch Witch	1
On Sea Ice, Day 2		
C-4, Berms on Sea Ice	Challenger	1
	Tracked Vehicle with Blade, e.g., Tucker Sno-Cat	1
C-11, C-12, Trenching on Ice	Ditch Witch Trencher, e.g., R-100	1
B-5 and B-6, Burning on Sea Ice	Challenger	1
	Tracked Vehicle with Blade, e.g., Tucker Sno-Cat	4
	Airboat to Tend Burning	4
	Airboat for Shuttling	1
	Rolligon with Auger	1
	Fire Boom	1,000 feet
B-3, Ignition on Ice	Helicopter	1
	Heli-torch	2
B-4 (3), Burning on Overflood Ponds	Airboat to Tend Burning	6
	Fire Boom, 500 feet each	1,500 feet
	Airboat for Towing and Shuttling	3



Northstar Well Blowout
During Typical Spring
Conditions
Days 22 - 30 in Early July

1" = Approx.
2.5 Miles

Figure 4

TABLE 4: PERSONNEL TO OPERATE OIL CONTAINMENT AND REMOVAL EQUIPMENT BEFORE BREAK-UP

LABOR CATEGORY	TACTIC	NO. STAFF PER TACTICAL UNIT	NO. TACTICAL UNITS	NO. STAFF PER SHIFT, DAYS 2 TO 6	NO. STAFF PER SHIFT, DAYS 6 TO 21
Team Leader	C-4	1	1	1	1
	B-5, B-6 on ice	1	5	5	5
	C-11, C-12	1	1	1	0
	B-3	1	1	1	1
	B-4, B-6 in overflood ponds	1	2	0	0
Vessel Operator >30 ft	B-4, B-6 in overflood ponds	1	2	2	0
Vessel Operator <30 ft	B-5, B-6 on ice	1	5	5	5
	B-4, B-6 in overflood ponds	1	8	8	0
Skilled Technician	B-5 on ice	1	4	4	4
	B-3	5	1	5	5
	B-4 on overflood ponds	2	8	16	0
General Technician	B-5	2	4	4	4
Equipment Operator	C-4	2	1	2	2
	B-5 on ice	2	4	4	4
	C-11, C-12	1.5	2	3	0
Total Operators and Technicians	-	-	-	53	26

* Vessel Operators are Team Leaders

<u>July 4 to 20</u>

Following break-up, teams target the 2,998 barrels that fall to sea ice pieces and water from July 1 to July 11 [249 bopd x 12 days = 2,988 bbl].

Vessels and mini-barges for recovery configurations mobilize at West Dock, travel to the spill scene and deploy on the same schedule.

Vessel configurations, each with a Crucial C Disc 13/30 skimmer, free skim in the drift ice (R-31B). Other teams also target oil outside the barrier islands where they encounter <1 tenths ice. Oil and water are stored immediately in mini-barges.

In situ burning continues as the broken ice coverage decreases (Tactic B-3 and B-4). A heli-torch ignites isolated pockets of oil on the water, oil in fireboom and oil on ice pieces. Pairs of workboats tow fireboom in U configurations between ice pieces. Two workboats collect burn residue with hand tools (B-6) and off-load it to lined dump trucks at West Dock. The residue quantity is estimated by volume measurements at West Dock.

Daily aerial surveillance continues until fast ice forms in October.

Table 5 and Table 6 list equipment and staff that remove oil in the broken ice period. Table 7 lists skimmer capacities.

TABLE 5: MAJOR OIL CONTAINMENT AND REMOVAL EQUIPMENT EQUIVALENTS NEEDED IN BROKEN ICE CONDITIONS

EQUIPMENT	EQUIPMENT PER TACTICAL UNITS	TOTAL QUANTITY
Workboat Type E (2) and Type D (1)		3
Crucial C Disc 13/30 Skimmer		3
Workboat Type D, shuttle	3 ea. R-31B	3
Mini-barge		6
Helicopter with heli-torch	1 ea. B-3	1
Workboat, Type B and C		4
Fireboom, 500 LF ea per day for 16 days	2 ea. B-4	16,000 LF
Workboat, Type C	2 ea. B-6	2

TABLE 6: PERSONNEL TO OPERATE OIL CONTAINMENT AND REMOVAL EQUIPMENT IN BROKEN ICE CONDITIONS

LABOR CATEGORY	TACTIC	NO. STAFF PER TACTICAL UNIT	NO. TACTICAL UNITS	NO. STAFF PER SHIFT TO JULY 11	NO. STAFF PER SHIFT, JULY 12 TO 22
Team Leader	R-31B (3), B-4 (2) B-6	1	9	9	9
Large Vessel Operator, >30 ft	R-31B	2	3	6	6
Small Vessel Operator, <30 ft	B-6	1	2	2	2
	B-4	1	2	2	2
Skilled Technicians	R-31B	5	3	15	15
	B-6	2	2	4	4
	B-4	2	2	4	4
Total Operators and Technicians	-	-	-	33	33

Total is sum of vessel operators and technicians; team leaders are vessel operators.

TABLE 7: SKIMMER CAPACITIES DURING BROKEN ICE PERIOD

A SKIMMER AND ICE CONDITION	B NO.	C DE-RATED OIL RECOVERY RATE (boph)	D DAILY EFFECTIVE OIL RECOVERY RATE (bopd) C X 20 HOURS	E SUM OF DAILY EFFECTIVE OIL RECOVERY RATES (bopd) B X D	F NO. DAYS	G TOTAL SKIMMER CAPACITY (bbl) E X F
RB-10 drum/brush, ice <1/10	2	28	554	1,108	27	29,916
Crucial C Disc 13/30 Skimmer R-31B, >5/10s	3	236	4,720	14,160	16	226,560

A Liquid Transfer Task Force assembles at West Dock. The stored liquids are offloaded from the storage barges to vacuum trucks (Tactic R-22). The volumes of stored oil and free water are gauged with ullage tape in the barge tanks.

The Environmental Unit includes a three-person Waste Management Team to (1) fill out and sign manifests; (2) measure liquid and other waste; and (3) submit a plan to ADEC for waste management. Burn residue and non-liquid oily wastes are transported to GPB for handling and ultimate disposal. Liquid and non-liquid oily wastes are processed as described in Tactics D-1 and D-2.

Shoreline cleanup teams recover oil on marine shorelines using methods recommended by the Shoreline Cleanup Assessment Teams, reflected in a shoreline cleanup plan and approved by the Unified Command (Tactics SH-1 to SH-12).

<u>July 20 to October 9</u>

In the ice-free season, in situ burning and mechanical oil recovery efforts continue. The heli-torch (B-3), fireboom (B-4), and detached J containment and skimming teams that operated in the broken ice earlier in July continue their efforts daily on day and night shifts in the ice-free conditions from late July to October. Their objective is to remove oil on the water that may remain after the earlier removal efforts. The B-4 rows in Table 5 and Table 6 list the equipment and staff of those on-water oil removal teams.

<u>After October 9</u>

As the nearshore Beaufort Sea freezes, oil removal operations are reduced and then suspended for the winter. The on-water teams continue to target oil for removal in the ice-free water areas. However, the teams avoid taking paths through areas where grease, slush and new ice are forming. See Tactic L-7.

During the freeze-up period, aerial monitoring continues. Patches of scattered oil are reported and mapped until the area supports fast ice.

THIS PAGE INTENTIONALLY LEFT BLANK

United States Department of the Interior

BUREAU OF SAFETY AND ENVIRONMENTAL ENFORCEMENT
WASHINGTON, DC 20240-0001

In Reply Refer To:
MS AE500

JUN 2 6 2013

Mr. Tony Parkin
BP Exploration (Alaska) Incorporated
PO Box 196612
Anchorage, Alaska 99519-6612

Dear Mr. Parkin:

Per the procedures described in your approved Northstar Oil Discharge Prevention and Contingency Plan (ODPCP), the Oil Spill Response Division (OSRD) received your changes by letter received on March 8, 2012. These changes are approved. However, during our review, we identified that your plan does not include an updated list of the leases covered by the plan as required by 30 CFR 254.53(b)(1).

Please submit a supplemental or updated ODPCP that includes a list of leases the plan covers to the OSRD Alaska Region Unit at the following address: Bureau of Safety and Environmental Enforcement, Oil Spill Response Division, Alaska Region Unit, 3801 Centerpoint Drive, Anchorage, Alaska 99503, Attention: Christy Bohl. If you have any questions regarding the information requested, please contact Ms. Christy Bohl at (907) 334-5309.

Sincerely,

David M. Moore

David M. Moore
Chief, Oil Spill Response Division

THIS PAGE INTENTIONALLY LEFT BLANK

U.S. COAST GUARD

NORTHSTAR OPERATIONS
OIL DISCHARGE PREVENTION AND CONTINGENCY PLAN

CROSS REFERENCE TO
U.S. COAST GUARD RESPONSE PLAN REQUIREMENTS [33 CFR 154]

REGULATION SECTION (33 CFR 154.1035)	REGULATORY TEXT	ODPCP SECTION
(a)	***Introduction and Plan Content.*** This section of the plan must include facility and plan information as follows:	Contents are in Volume 1 (Response Action Plan) unless otherwise indicated
(a)(1)	The facility's name, street address, city, county, state, ZIP code, facility telephone number, and telefacsimile number, if so equipped. Include mailing address if different from street address.	Page i
(a)(2)	The facility's location described in a manner that could aid both a reviewer and a responder in locating the specific facility covered by the plan, such as, river mile or location from known landmark that would appear on a map or chart.	Introduction
(a)(3)	The name, address, and procedures for contacting the facility's owner or operator on a 24-hour basis.	Sections 1.1, 1.2 and Table 1-3
(a)(4)	A table of contents.	Table of Contents
(a)(5)	During the period that the submitted plan does not have to conform to the format contained in this subpart, a cross-index, if appropriate.	This Section
(a)(6)	A record of change(s) to record information on plan updates.	ROR-1
(b)	***Emergency Response Action Plan.*** This section of the plan must be organized in the subsections described in this paragraph:	
(b)(1)	*Notification procedures.*	
(b)(1)(i)	This section must contain a prioritized list identifying person(s), including name, telephone number, and their role in the plan, to be notified of a discharge or substantial threat of a discharge of oil. The telephone number need not be provided if it is listed separately in the list of contacts required in the plan. This Notification Procedures listing must include-	Sections 1.1, 1.2 and Tables 1-1, 1-2 and 1-3
(b)(1)(i)(A)	Facility response personnel, the spill management team, oil spill removal organizations, and the qualified individual(s) and the designated alternate(s); and	Sections 1.1, 1.2, 3.8, Table 1-1, 1-2 and 1-3
(b)(1)(i)(B)	Federal, State, or local agencies, as required.	Section 1.2 and Table 1-4

CROSS REFERENCE (Continued)
TO U.S. COAST GUARD RESPONSE PLAN REQUIREMENTS
[33 CFR 154.1035]

REGULATION SECTION (33 CFR 154.1035)	REGULATORY TEXT	ODPCP SECTION
(b)(1)(ii)	This section must include a form, which contains information to be provided in the initial and follow-up notifications to Federal, State and local agencies. The form shall include notification of the National Response Center as required in Part 153 of this chapter. Copies of the form also must be placed at the location(s) from which notification may be made. The initial notification form must include space for the information contained in Figure 1. The form must contain a prominent statement that initial notification must not be delayed pending collection of all information.	Section 1.2, Figure 1-3, and this section.
(b)(2)	*Facility's spill mitigation procedure.*	
(b)(2)(i)	This subsection must describe the volume(s) and oil groups that would be involved in the -	
(b)(2)(i)(A)	Average most probable discharge from the MTR facility;	This Section
(b)(2)(i)(B)	Maximum most probable discharge from the MTR facility;	This Section
(b)(2)(i)(C)	Worst case discharge from the MTR facility; and	This Section
(b)(2)(i)(D)	Where applicable, the worst case discharge from non-MTR facility. This must be the same volume provided in the response plan for the non-transportation-related facility.	Section 1.6.4
(b)(2)(ii)	This subsection must contain prioritized procedures for facility personnel to mitigate or prevent any discharge or substantial threat of a discharge of oil resulting from operational activities associated with internal or external facility transfers including specific procedures to shut down affected operation. Facility personnel responsible for performing specified procedures to mitigate or prevent any discharge or potential discharge shall be identified by job title. A copy of these procedures shall be maintained at the facility operations center. These procedures must address actions to be taken by facility personnel in the event of a discharge, potential discharge, or emergency involving the following equipment and scenarios:	Section 1.6.4, Table 1-1; Volume 2, Sections 2.1.5 through 2.1.10, 2.5 and 3.1.3, Table 2-5
(b)(2)(ii)(A)	Failure of manifold, mechanical loading arm, other transfer equipment or hoses, as appropriate;	Section 1.6.4
(b)(2)(ii)(B)	Tank overfill;	Volume 2, Sections 2.1.5, 2.1.8 and 2.5.5
(b)(2)(ii)(C)	Tank failure;	Section 1.6.4; Volume 2, Section 2.5.5
(b)(2)(ii)(D)	Piping rupture;	Section 1.6.4; Volume 2, Sections 2.5.2 through 2.5.4, 2.5.6, and 2.5.7
(b)(2)(ii)(E)	Piping leak, both under pressure and not under pressure, if applicable;	Section 1.6.4; Volume 2, Sections 2.5.2 through 2.5.4, 2.5.6, and 2.5.7
(b)(2)(ii)(F)	Explosion or fire; and	Section 1.6.4

CROSS REFERENCE (Continued)
TO U.S. COAST GUARD RESPONSE PLAN REQUIREMENTS
[33 CFR 154.1035]

REGULATION SECTION (33 CFR 154.1035)	REGULATORY TEXT	ODPCP SECTION
(b)(2)(ii)(G)	Equipment failure (e.g., pumping system failure, relief valve failure, or other general equipment relevant to operational activities associated with internal or external facility transfers.)	Sections 1.6.4; Volume 2, Section 2.5
(b)(2)(iii)	This subsection must contain a listing of equipment and the responsibilities of facility personnel to mitigate an average most probable discharge.	Sections 1.6.4 and 3.6
(b)(3)	*Facility's response activities.*	
(b)(3)(i)	This subsection must contain a description of the facility personnel's responsibilities to initiate a response and supervise response resources pending the arrival of the qualified individual.	Section 1.1 and Table 1-1
(b)(3)(ii)	This subsection must contain a description of the responsibilities and authority of the qualified individual and alternate as required in §154.1026.	Section 1.2.4
(b)(3)(iii)	This subsection must describe the organization structure that will be used to manage the response actions. This structure must include the following functional areas.	Sections 1.1, 3.3, Tables 1-1, 1-2 and Figure 1-2
(b)(3)(iii)(A – H)	Command and control; Public information; Safety; Liaison with government agencies; Spill Operations; Planning; Logistics support; and Finance.	Sections 1.1, 3.3, Tables 1-1, 1-2 and Figure 1-2
(b)(3)(iv)	This subsection must identify the oil spill removal organizations and the spill management team that will be capable of providing the following resources:	Sections 3.5, 3.6 and 3.9
(b)(3)(iv)(A)	Equipment and supplies to meet the requirements of §§154.1045, 154.1047, or subparts H or I of this part, as appropriate.	Section 3.6
(b)(3)(iv)(B)	Trained personnel necessary to continue operation of the equipment and staff the oil spill removal organization and spill management team for the first 7 days of the response.	Sections 3.5 and 3.9
(b)(3)(v)	This subsection must include job descriptions for each spill management team member within the organization structure described in (b)(3)(iii) of this section. These job descriptions must include the responsibilities and duties of each spill management team member in a response action.	Sections 1.1 and 3.9 and Table 1-1

CROSS REFERENCE (Continued)
TO U.S. COAST GUARD RESPONSE PLAN REQUIREMENTS
[33 CFR 154.1035]

REGULATION SECTION (33 CFR 154.1035)	REGULATORY TEXT	ODPCP SECTION
(b)(3)(vi)	For facilities that handle, store, or transport group II through group IV petroleum oils, and that operate in waters where dispersant use is pre-authorized, this subsection of the plan must also separately list the resource provides and specific resources, including appropriately trained dispersant-application personnel, necessary to pride the dispersant capabilities resources in this subpart. All resource providers and resources must be available by contract or other approved means as described in §154.1028(a). The dispersant resources to be listed within this section must include information described in §154.1035(b)(3)(vi)(A – D).	Not applicable
(b)(3)(vii)	This subsection of the plan must also separately list the resource providers and specific resources necessary to provide aerial oil tracking capabilities required in this subpart. The oil tracking resources to be listed within this section must include the following:	Sections 1.6.4 and 3.6
(b)(3)(vii)(A)	The identification of a resource provider; and	Section 1.1 and 3.6. Table 1-1,
(b)(3)(vii)(B)	Type and location of aerial surveillance aircraft that are ensured available, through contract or other approved means, to meet the oil tracking requirements of §154.1045(j).	Section 1.6.4, ACS *Technical Manual*, Tactics T-2 and T-4
(b)(3)(viii)	For mobile facilities that operate in more than one COTP zone, the plan must identify the oil spill removal organization and the spill management team in the applicable geographic-specific appendix. The oil spill removal organization(s) and the spill management team discussed in paragraph (b)(3)(iv) of this section must be included for each COTP zone in which the facility will handle, store, or transport oil in bulk.	Not applicable
(b)(3)(ix)	For mobile facilities that operate in more than one COTP zone, the plan must identify the oil spill removal organization and the spill management team in the applicable geographic-specific appendix. The oil spill removal organization(s) and the spill management team discussed in paragraph (b)(3)(iv)(A) of this section must be included for each COTP zone in which the facility will handle, store, or transport oil in bulk.	Not applicable
(b)(4)	*Fish and wildlife and sensitive environments.*	
(b)(4)(i)	This section of the plan must identify areas of economic importance and environmental sensitivity, as identified in the ACP, which are potentially impacted by a worst case discharge. ACPs are required under section 311(j)(4) of the FWPCA to identify fish and wildlife and sensitive environments. The applicable ACP shall be used to designate fish and wildlife and sensitive environments in the plan. Changes to the ACP regarding fish and wildfire and sensitive environments shall be included in the annual update of the response plan, when available.	Sections 1.6.4 and 3.10

CROSS REFERENCE (Continued)
TO U.S. COAST GUARD RESPONSE PLAN REQUIREMENTS
[33 CFR 154.1035]

REGULATION SECTION (33 CFR 154.1035)	REGULATORY TEXT	ODPCP SECTION
(b)(4)(ii)	For a worst case discharge from the facility, this section of the plan must -	
(b)(4)(ii)(A)	List all fish and wildlife and sensitive environments identified in the ACP which are potentially impacted by a discharge of persistent oils, non-persistent oils, or non-petroleum oils.	Sections 1.6.4 and 3.10
(b)(4)(ii)(B)	Describe all the response actions that the facility anticipates taking to protect these fish and wildlife and sensitive environments.	Sections 1.6.4 and 3.10
(b)(4)(ii)(C)	Contain a map or chart showing the location of those fish and wildlife and sensitive environments which are potentially impacted. The map or chart shall also depict each response action that the facility anticipates taking to protect these areas. A legend of activities must be included on the map page.	Section 1.6.4
(b)(4)(iii)	For a worst case discharge, this section must identify appropriate equipment and required personnel, a available by contract or other approved means as described in §154.1028, to protect fish and wildlife and sensitive environments which fall within the distances calculated using the methods outlined in this paragraph as follows:	Sections 1.6.4 and 3.6
(b)(4)(iii)(A)	Identify the appropriate equipment and required personnel to protect all fish and wildlife and sensitive environments in the ACP for the distance, as calculated in paragraph (b)(4)(iii)(B) of this section, that the persistent oils, non-persistent oils, or non-petroleum oils are likely to travel in the noted geographic area(s) and number of days listed in table 2 of appendix C of this part;	Five mile circumference from barge mooring location; Sections 1.6.4, 3.5, 3.6, 3.8 and 3.9
(b)(4)(iii)(B)	Calculate the distance required by paragraph (b)(4)(iii)(A) of this section by selecting one of the methods described in§154.1035(b)(4)(iii)(B)(i - iii);	This Section
(b)(4)(iii)(C)	Based on historical information or a spill trajectory or model, the COTP may require the additional fish and wildlife and sensitive environments also be protected.	Not applicable
(b)(5)	*Disposal plan.* This subsection must describe any actions to be taken or procedures to be used to ensure that all recovered oil and oil contaminated debris produced as a result of any discharge are disposed according to Federal, state, or local requirements.	Sections 1.6.3 and 1.6.4
(c)	***Training and Exercises.*** This subsection must be divided into the following two subsections:	
(c)(1)	*Training procedures*. This subsection must describe the training procedures and programs of the facility owner or operator to meet the requirements in §154.1050	Section 3.9; Volume 2, Section 2.1.1
(c)(2)	*Exercise procedures*. This subsection must describe the exercise program to be carried out by the facility owner or operator to meet the requirements in §154.1055.	Section 3.9

CROSS REFERENCE (Continued)
TO U.S. COAST GUARD RESPONSE PLAN REQUIREMENTS
[33 CFR 154.1035]

REGULATION SECTION (33 CFR 154.1035)	REGULATORY TEXT	ODPCP SECTION
(d)	***Plan review and update procedures.*** This section must address the procedures to be followed by the facility owner or operator to meet the requirements of §154.1065 and the procedures to be followed for any post-discharge review of the plan to evaluate and validate its effectiveness.	Introduction
(e)	***Appendices.*** This section of the response plan must include the appendices described in this paragraph.	
(e)(1)	*Facility-specific information.* This appendix must contain a description of the facility's principal characteristics.	
(e)(1)(i)	There must be a physical description of facility including a plan of the facility showing the mooring areas, transfer locations, control stations, locations of safety equipment, and the location and capacities of all piping and storage tanks.	Volume 2, Section 3.1 and This Section (Figure 1)
(e)(1)(ii)	The appendix must identify the sizes, types, and number of vessels that the facility can transfer oil to and from simultaneously.	Northstar does not have multiple fuel transfer capabilities. Fuel transfer operations are limited to one barge at a time. The barges that would be used for diesel fuel transfers are approximately 250-foot length, 50-foot beam, and have a draft of approximately seven feet.
(e)(1)(iii)	The appendix must identify the first valve(s) on facility piping separating the transportation-related portion of the facility from the non-transportation-related portion of the facility, if any. For piping leading to a manifold located on a dock serving tank vessels, this valve is the first valve inside the secondary containment required by 40 CFR 112.	Valves are at the bulk storage tank and located within secondary containment. Refer to Figure 1 (this Section).
(e)(1)(iv)(A – E)	The appendix must contain information on oil(s) and hazardous material handled, stored, or transported at the facility in bulk. A material safety data sheet meeting the requirements of 29 CFR 1910.1200, 33 CFR 154.310(a)(5) or an equivalent will meet this requirement. This information can be maintained separately providing it is readily available and the appendix indentifies its location. This information must include – the generic or chemical name; a description of the appearance and odor; the physical and chemical characteristics; the hazards involved in handling the oil(s) and hazardous materials (this shall include hazards likely to be encountered if the oil(s) and hazardous materials come in contact as a result of a discharge); and a list of fire-fighting procedures and extinguishing ages effective with fires involve the oil(s) and hazardous materials.	Material Data Safety Sheets are available in the Fuel Transfer Operations Manual (33 CFR 154.300), maintained at the Northstar facility.
(e)(1)(v)	The appendix may contain any other information which the facility owner or operator determines to be pertinent to an oil spill response.	Not applicable

CROSS REFERENCE (Continued)
TO U.S. COAST GUARD RESPONSE PLAN REQUIREMENTS
[33 CFR 154.1035]

REGULATION SECTION (33 CFR 154.1035)	REGULATORY TEXT	ODPCP SECTION
(e)(2)	*List of contacts.* This appendix must include information on 24-hour contact of key individuals and organizations. If more appropriate, this information may be specified in a geographic-specific appendix. The list must include -	Sections 1.1 and 1.2, Tables 1-1 through 1-4
(e)(2)(i)	The primary and alternate qualified individual(s) for the facility.	Section 1.1, Table 1-3
(e)(2)(ii)	The contact(s) identified under paragraph (b)(3)(iv) of this section for activation of the response resources.	Section 1.1, Tables 1-1 and 1-3
(e)(2)(iii)	Appropriate Federal, State, and local officials.	Section 1.2, Table 1-4
(e)(3)	*Equipment list and records.* This appendix must include the information specified in this paragraph.	
(e)(3)(i)	This appendix must contain a list of equipment and facility personnel required to respond to an average most probable discharge, as defined in §154.1020. The appendix must also list the location of the equipment.	Sections 1.1, 1.6.4, 3.3, 3.5, 3.6, and 3.8
(e)(3)(ii)	The appendix must contain a detailed listing of all their major equipment identified in the plan as belonging to an oil spill response organization(s) that is available, by contract or other approved means as described in §154.1028(a), to respond to a maximum most probable or worst case discharge, as defined in §154.1020. The detailed listing of all major equipment may be located in a separate document referenced by the plan. Either the appendix or the separate document referenced in the plan must provide the location of the major response equipment.	Section 3.6 and ACS *Technical Manual*, Volume 1, Tactic L-6
(e)(3)(iii)	It is not necessary to list response equipment from oil spill removal organization(s) when the organization has been classified by the Coast Guard and their capacity has been determined to equal or exceed the response capability needed by the facility. For oil spill removal organization(s) classified by the Coast Guard, the classification must be noted in this section of the plan. When it is necessary for the appendix to contain a listing of response equipment, it shall include all of the following items that are identified in the response plan: Skimmers; booms; dispersant application, in-situ burning, bioremediation equipment and supplies, and other equipment used to apply other chemical agents on the NCP Product Schedule (if applicable); communications, firefighting, and beach cleaning equipment; boats and motors; disposal and storage equipment; and heavy equipment. The list must include for each piece of equipment – items listed in §154.1035(e)(iii)(A-H).	Section 3.6

CROSS REFERENCE (Continued)
TO U.S. COAST GUARD RESPONSE PLAN REQUIREMENTS
[33 CFR 154.1035]

REGULATION SECTION (33 CFR 154.1035)	REGULATORY TEXT	ODPCP SECTION
(e)(4)	*Communications Plan*. This appendix must describe the primary and alternate method of communication during discharges, including communications at the facility and remote locations within the areas covered by the response plan. The appendix may refer to additional communications packages provided by the oil spill removal organization. This may reference another existing plan or document.	Section 1.4
(e)(5)	*Site-Specific Health and Safety Plan*. This appendix must describe the safety and health plan to be implemented for any response location(s). It must provide as much detailed information as is practicable in advance of an actual discharge. This appendix may reference another existing plan requiring under 29 CFR 1910.120.	Emergency Action Plan for Northstar maintained on BPXA's intranet website. Available upon request.
(e)(6)	*List of Acronyms and Definitions*. This appendix must list all acronyms used in the response plan including any terms or acronyms used by Federal, State, or local governments and any operational terms commonly used at the facility. This appendix must include all definitions that are critical to understanding the response plan.	Table of Contents

Notification Form [30 CFR 154.1035(b)(1)(ii)]

The National Response Center (NRC) Vessel Report Form has been included (Figure 1 of this section) for use as a training tool and guide when notifying the NRC. It is also available online at: http://www.nrc.uscg.mil/vesselreport.html. (BPXA's North Slope Spill Report Form can also be found in Figure 1.3 of the Oil Discharge Prevention and Contingency Plan).

Average Most Probable Discharge [30 CFR 154.1035(b)(2)(i)(A)]

The average most probable discharge is calculated as approximately 0.5 bbl of diesel fuel, based on the definition contained in 33 CFR 154.1020 (the lesser of 50 bbl or 1 percent of the volume of the worst case discharge).

Maximum Most Probable Discharge [30 CFR 154.1035(b)(2)(i)(B)]

(b) (7)(F), (b) (3)

[redacted]

Worst Case Discharge [30 CFR 154.1035(b)(2)(i)(C)]

(b) (7)(F), (b) (3)

[redacted]

Physical Description [30 CFR 154.1035(e)(1)(i)]

Refer to Figure 2 for an illustration of the facility and details regarding fuel transfer operations.

FIGURE 1: NRC VESSEL REPORT FORM

Fields displayed in RED and with an * are mandatory entries. Please fill out the form as completely as possible.				
Note: It is not necessary to wait for all information before calling NRC. National Response Center—1–800–424–8802 or direct telephone: 202–267–2675.				
* Is this a DRILL Report ?	Yes/No	* E-Mail Address:		
REPORTING PARTY		**SUSPECTED RESPONSIBLE PARTY**		
* Phone 1:	Type:	* Last Name:		
* Last Name:		First Name:		
First Name:		Phone 1:	Type (Work, Cell, etc):	
Phone 2:	Type (Work, Cell etc):	Phone 2:	Type:	
Phone 3:	Type:	Phone 3:	Type:	
Company:		Company:		
* Org Type (Private Enterprise, Federal Govt., State Etc):		* Org Type (Private Enterprise, Federal Govt., State Etc):		
Address:		Address:		
City:		City:		
* State:		* State:		
ZIP:		ZIP:		
Are you calling on behalf of responsible party:		Yes/No		
Are you or your company responsible for Material released:		Yes/No		
INCIDENT DESCRIPTION				
* Description of Incident:				
* Incident Date:	* Time:	* Occurred/Discovered/Planned:		
Type of Incident: VESSEL	* Incident Cause:			
INCIDENT LOCATION				
* Location Description:				
* Address Location:		* State: * County: ZIP:		
Nearest City:	Distance from Nearest City:		Units:	
Direction:	Range:	Section:	Township:	
Latitude: Degrees:	Minutes:	Seconds:	Quadrant:	
Longitude: Degrees:	Minutes:	Seconds:	Quadrant:	
VESSEL DETAILS				
VESSEL #1				
* Vessel Type:		* Vessel Name:		
Vessel #:	Flag:	Length:	Beam:	Draft:
Hull Construction:		* Vessel Aground:	Yes/No	
Fuel Capacity:	Unit:	Fuel on Board:	Unit:	
Cargo Capacity:	Unit:	Cargo on Board:	Unit:	
VESSEL #2				
* Vessel Type:		* Vessel Name:		
Vessel #:	Flag:	Length:	Beam:	Draft:
Hull Construction:		* Vessel Aground:	Yes/No	
Fuel Capacity:	Unit:	Fuel on Board:	Unit:	
Cargo Capacity:	Unit:	Cargo on Board:	Unit:	
MATERIAL INVOLVED				
MATERIAL #1				
* Material:		CHRIS Code:	CAS Code:	
* Amount Released:	* Units:	Amount in Water:	Units:	

FIGURE 1 (CONTINUED): NRC VESSEL REPORT FORM

MATERIAL IN WATER INFORMATION			
Body of Water Affected:	Offshore:	Yes/No:	No River Mile Marker:
Tributary of:	Water Supply Contaminated:	Yes/No/Unknown	
Water Temperature:	Units:		
Wave Condition:	Speed:	Units:	Direction:
SHEEN INFORMATION			
Sheen Length:	Units:	Sheen Width:	Units:
Color:		Direction of Movement:	
Odor Description:			
IMPACT INFORMATION			
Medium Affected:		Detailed Medium Information:	
Fire:	Yes/No/Unknown	Fire Extinguished:	Yes/No/Unknown
Injuries:	Yes/No/Unknown	Number of Injuries: Number to Hospital: Rail Employee Injuries: Rail Passenger Injuries:	
Fatalities:	Yes/No/Unknown	Number of Fatalities: Employee Fatalities: Passenger Fatalities: Vehicle Fatalities:	
Evacuations:	Yes/No/Unknown	Number Evacuated: Radius/Area in Miles: Who was Evacuated:	
Damages:	Yes/No/Unknown	Damage in Dollars:	
Road Closed:	Yes/No/Unknown	Road: Major Artery: Hours Closed: Direction of Closure:	 Yes/No
Track Closed: Passengers Transferred:	Yes/No/Unknown Yes/No/Unknown	Track: Hours Closed: Direction of Closure:	
Air Corridor Closed:	Yes/No/Unknown	Air Corridor: Hours Closed:	
Waterway Closed:	Yes/No/Unknown	Waterway: Hours Closed:	
Environmental Impact:	Yes/No/Unknown	Type of Impact: Media Interest:	
WEATHER INFORMATION			
Weather Conditions:	Air Temperature:	Unit:	
Wind Speed:	Unit:	Wind Direction:	
REMEDIAL ACTION INFORMATION			
Remedial Action Taken:			
Release Secured:	Yes/No/Unknown	Release Duration:	Unit:
Rate of Release:	Unit:	Per:	
ADDITIONAL AGENCY INFORMATION			
Federal Agency Notified:			
State/Local Agency Notified:			
State/Local Agency On-Scene:			
State Agency's Report Number:			
ADDITIONAL INFORMATION			
Additional Information:			

FIGURE 2: NORTHSTAR ISLAND FUEL OFFLOADING VALVE LOCATION MAP

(b) (7)(F), (b) (3)

[redacted]

U.S. Department of
Homeland Security

United States
Coast Guard

Captain of the Port
United States Coast Guard
Western Alaska

510 L Street, Suite 100
Anchorage, AK 99501
Staff Symbol: spi
Phone: (907) 271-6700
FAX: (907) 271-6751
WesternAlaskaFacilities@uscg.mil

16611/ANC-P-026
October 2, 2012

BP Exploration (Alaska), Inc.
Attn: Anthony Parkin
900 E. Benson Boulevard
Anchorage, AK 99508

Subj: FACILITY RESPONSE PLAN (FRP)

Ref: (a) BPXA Northstar FRP received September 28, 2012

Dear Mr. Parkin:

Reference (a) is "**Approved**" as a significant and substantial harm facility. Your FRP will expire October 2, 2017. An annual review of the FRP shall be conducted in accordance with Title 33 Code of Federal Regulations Part 154.1065, and any revisions shall be submitted to the Captain of the Port within thirty days of the change. If no revisions are required, the facility owner or operator shall indicate the completion of the annual review on the record of changes page.

This letter must be kept in the front of your FRP for review by Coast Guard personnel during inspections. Any future correspondence should include your facility's unique identification number (ANC-P-026).

Questions or comments concerning your FRP shall be directed to the Facilities Branch at Sector Anchorage: (907) 271-6718. Submit any revisions to the above address.

Sincerely,

N. S. MENEFEE
Lieutenant, U. S. Coast Guard
Assistant Chief, Inspections Division
By direction

Copy: Facility File

BP EXPLORATION (ALASKA), INC.

NORTHSTAR OIL DISCHARGE PREVENTION AND CONTINGENCY PLAN

Volume 2 of 2, Prevention Plan

MARCH 2012

RECORD OF REVISIONS FOR VOLUME 2

REVISION NUMBER	REVISION DATE	SUMMARY OF REVISION CHANGE
1	Sept. 2012	**Appendix A (Portable Shop-Fabricated Tank Table),** The following changes were made: • CIC Tank Integrity Inspection dates were updated; • Removed from service/surplussed tanks 73011 (GPB), 73031 (GPB), END-02 (END SDI) were deleted; and • DOT-regulated tank 90-869 was removed because it is not regulated by ADEC.
2	April 2013	**Appendix A:** The following changes were made to the Portable Shop-Fabricated Tank Table: • CIC Tank Integrity Inspection updates were updated; • Tank T-100420 was removed; and • Tanks T-20451 and T-20452 were tagged as not in service.
3	November 2013	**Appendix A:** The following changes were made to the Portable Shop-Fabricated Tank Table: • A column designating tank owner was added; • ASRC tanks 01-09 through 01-14 were removed since the tanks are no longer located on BP Exploration (Alaska), Inc. (BPXA) leases; • TANK-O tank O-17, a single-walled open top tank, was added; and • The tag number for TANK-O tank T-12 was corrected to O-12.
4	April 2014	**Appendix A:** The following changes were made to the Portable Shop-Fabricated Tank Table: • CIC Tank Integrity Inspection updates were updated; • Tank T-4127E and Tank T-1103 (Formerly O-1 CTU-01) were removed.
5	July 2014	**Part 2:** • Added a sentence to Section 2.1.9 stating open top double-wall tanks will have lids in place while in use. **Appendix A:** The following changes were made to the Portable Shop-Fabricated Tank Table: • Added ADEC-complaint double-walled tanks T-22 thru T-33; • Updated the description of Tank O-12.

THIS PAGE INTENTIONALLY LEFT BLANK

TABLE OF CONTENTS FOR VOLUME 2

PHMSA 000109527

APPENDICES

LIST OF FIGURES FOR VOLUME 2

LIST OF TABLES FOR VOLUME 2

THIS PAGE INTENTIONALLY LEFT BLANK

LIST OF ACRONYMS FOR VOLUME 2

AAC	Alaska Administrative Code
ACS	Alaska Clean Seas
ADEC	Alaska Department of Environmental Conservation
AE	acoustic emissions
ANSI	American National Standards Institute
AOGCC	Alaska Oil and Gas Conservation Commission
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
ATP	Authorization to Proceed
BAT	best available technology
bopd	barrels of oil per day
BPXA	BP Exploration (Alaska), Inc.
CFR	Code of Federal Regulation
CIC	Corrosion, Inspection and Chemicals
DOT	U.S. Department of Transportation
EAP	Employee Assistance Program
EFA	Ed Farmer & Associates
°C	degrees Celsius
°F	degrees Fahrenheit
FBE	fusion bonded epoxy
FLIR	Forward Looking Infrared
H_2S	hydrogen sulfide
HCP	Hearing Conservation Program
HMI	human-machine interface
HSSEE	Health, Safety, Security, Environment and Engineering
LEOS	Leck Erkennung und Ortangs System
MB	mass balance
MBLPC	mass balance line pack compensation
MIC	microbiologically influenced corrosion
MTT	Multi-Task Technician
NGL	natural gas liquid
NPWM	negative pressure wave monitoring
NSTC	North Slope Training Cooperative
ODPCP	oil discharge prevention and contingency plan
OSHA	Occupational Safety and Health Administration
PCS	process control system
PHMSA	Pipeline and Hazardous Materials Safety Administration
PLC	programmable logic control
PPA	pressure point analysis
psig	pounds per square inch gauge

PHMSA 000109531

RPP	Respiratory Protection Program
RTTM	real time transient model
SCADA	supervisory control and data acquisition
STI	Steel Tank Institute
USCG	U.S. Coast Guard
USACE	U.S. Army Corps of Engineers
VSM	vertical support member

INTRODUCTION

Volume 2 of this Oil Discharge Prevention and Contingency Plan (ODPCP) addresses oil spill prevention requirements promulgated by the State of Alaska in Title 18, Chapter 75 of the Alaska Administrative Code (AAC). As allowed under 18 AAC 75.425(e)(2), the ODPCP is represented by two volumes: Volume 1, Response Action Plan, and Volume 2, Prevention Plan. The Prevention Plan, Volume 2 of 2, is contained herein.

PLAN DISTRIBUTION

The Prevention Plan is maintained on the BP Exploration (Alaska), Inc. (BPXA) intranet website, accessible by BPXA employees and contractors. Hard copies of the plan are distributed to regulatory agencies and emergency operations centers. Additional copies are in the Anchorage Crisis Center; the Health, Safety, Security, Environment and Engineering (HSSEE) Department; and at Alaska Clean Seas (ACS). A record of plan distribution is maintained by the HSSEE Department.

UPDATING PROCEDURES

The Prevention Plan is reviewed annually and revised and updated when changes occur. Below is a list of key factors that may cause revisions to the plan:

- New developments,
- New pipeline construction or purchase,
- Change in commodities transported,
- Change in prevention procedures, or
- Change in ownership.

Modifications to the plan are considered amendments and must be reviewed and approved by the Alaska Department of Environmental Conservation (ADEC). Plan amendments are submitted within 30 days of revising the plan.

Revisions are documented in the Record of Revisions table at the beginning of this volume and posted on the BPXA intranet site for BPXA employee and contractor reference. Hard copies of the changed pages are distributed to regulatory agencies and emergency operations centers. Upon receipt of revisions, the copy holder replaces pages as instructed. It is the responsibility of each plan recipient to ensure that updates are promptly incorporated into the plan.

PLAN RENEWAL

The plan is renewed every five years, based on the State of Alaska's renewal cycle.

ACKNOWLEDGMENTS

Gratitude is extended to the many contributors who helped revise Volume 2 of the ODPCP. The following BPXA personnel oversaw revisions:

Bryant, Bill Croak, Jim Kuykendall, Wayne	Part 2, Section 3.1.4
Bronson, Mike	Entire volume
Bulot, Barry Helmandollar, Troy Rogers, Brad Vassen, Kendal	Sections 2.1.7, 2.5.6
Cocklan-Vendl, Mary Dowling, Peter Pomeroy, Glen	Sections 2.1.10, 2.5.8
Ervin, Tina	Sections 2.5.7, 3.1.4
Glover, Nick	Section 2.3
Gross, Terry	Section 2.1.8, Table 3-1, Appendix A
Kany, Geoff	Sections 2.1.5, 2.1.9
Kuzma, John Johnson, Elden Stelley, Travis	Sections 2.1.10, 4.8, 4.9
Smith, Angi	Sections 2.1.2, 2.1.3
Wood, Ken	Section 2.5.3, 2.5.4

Additional contributors were as follows:

Carr, Aaron, AeroMetric Cartographer	Appendix B, Facility Diagrams.
Ervin, Hunter, ACS	Sections 2.1.9, 2.5.7, Table 2-6
Kendall, Mer, Oasis Environmental	Appendix C, Discharge History
Miner, Lydia, SLR International Corp	Entire volume

PHMSA 000109534

PART 1. RESPONSE ACTION PLAN [18 AAC 75.425(e)(1)]

Part 1, Response Action Plan, is in Volume 1.

PART 2. PREVENTION PLAN [18 AAC 75.425(e)(2)]

This part describes how Northstar meets the applicable parts of 18 AAC 75, Article 1. The descriptions in this part reflect a number of BPXA's internal guidance documents not incorporated into this plan.

2.1 PREVENTION, INSPECTION, AND MAINTENANCE PROGRAMS [18 AAC 75.425(e)(2)(A)]

The facility's oil spill prevention programs consist of the equipment and activities required by applicable parts of the Alaska Department of Environmental Conservation (ADEC) oil spill prevention regulations (18 AAC 75 Article 1).

2.1.1 OIL DISCHARGE PREVENTION TRAINING PROGRAMS [18 AAC 75.020(a) to (c)]

BP Exploration (Alaska) Inc. (BPXA) employees with job duties directly involving inspection, maintenance or operation of oil storage and transfer equipment on BPXA leases are trained by way of BPXA's Oil Discharge Prevention Regulation Training course or discipline-specific modules. The oil spill prevention program includes lists of positions, job qualifications and individuals' training plans. BPXA has lists of employees who handle ADEC-regulated oil equipment and are subject to the training required by the regulatory agency. (The terms "oil storage" and "transfer equipment" mean tanks and secondary containment areas described in Part 3 of this plan, plus the facility piping and truck fluid transfer equipment on BPXA leases and as described in 18 AAC 75, Article 1.)

BPXA also requires contractor "oil handlers" to have training required by the regulations. Contractors may train by way of BPXA's program or by way of their own programs. Contractors record the completions of their spill prevention training that complies with the regulations. They make tallies of the completions available to BPXA primarily by way of ISNetworld's internet service. In turn, BPXA spot-checks the contractors' reports to determine whether contractor companies are training oil-handling staff regarding spill prevention.

Oil handlers also receive training on the operation and maintenance of oil equipment, oil spill protocols, and general facility operations. Oil spill prevention training and oil spill prevention briefings for oil-handling personnel are held annually. In addition, unescorted workers on BPXA leases receive spill prevention training through the North Slope Training Cooperative (NSTC) program.

BPXA maintains records of its employees' oil spill prevention training required by 18 AAC 75 Article 1. Records are kept for at least five years. They are provided to the ADEC upon request. Contractors maintain their own training records.

BPXA employees and contractor personnel working on the North Slope receive copies of the *North Slope Environmental Field Handbook*. It provides an overview of state and federal spill prevention regulations and programs applicable to the North Slope oil fields and summarizes procedures to comply with those regulations. In particular, the handbook explains fluid transfer procedures, drip liner usage, secondary containment, and spill reporting.

Facility and response personnel are provided a mandatory site orientation that includes familiarization with facility Emergency Response Plans.

Facility personnel also receive training on the BPXA Environmental Management System. BPXA's Environmental Management System promotes continual improvement in environmental performance. The system uses direct input from technical specialists and field personnel, and information developed through routine loss control and incident investigations, to minimize the potential recurrence of events. Environmental communications and bulletins are regularly distributed to ensure specific safety and environmental issues are communicated. Most supervisors discuss environmental communications and bulletins with their crews during daily and weekly toolbox safety meetings.

2.1.2 SUBSTANCE ABUSE PROGRAMS [18 AAC 75.007(e)]

BPXA policy provides guidance for an environment free of substance abuse, related accidents, and emergencies. This environment is maintained through adherence to strict alcohol and drug abuse policies and professionally recognized rehabilitation programs. The company has jurisdiction to intervene and impose disciplinary measures when problems are identified.

The BPXA drug policy promotes the safety of employees, contractors and non-employees, and provides a safe working environment. The company prohibits the following in the workplace or on the job:

- Possession of illicit drugs or alcohol;
- Possession of controlled substances without a physician assistant's knowledge;
- Under the influence of any illicit drug, alcohol, or the misuse of prescription medications; and
- Distribution or sale of drugs or alcohol.

BPXA complies with the U.S. Department of Transportation (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) drug and alcohol testing regulations set forth in Title 49 of the Code of Federal Regulations (CFR) Part 199, and the DOT Procedures for Transportation Workplace Drug & Alcohol Testing Programs in 49 CFR Part 40. BPXA employees involved in safety-sensitive positions within natural gas, liquefied natural gas, and hazardous liquid pipeline operations are required to undergo pre-employment biological testing and testing for reasonable cause, post-accident (per the definition stated in the respective drug testing procedure), return to duty, follow-up alcohol or drug testing (post-rehabilitation), and on a random basis in accordance with this regulation. Other BPXA employees fall under the company's drug testing program. Each of these groups is randomly tested at a rate of a minimum of 25 percent per year. Contract personnel maintain their own drug testing program records. The testing must meet the minimum standards set by BPXA.

BPXA employees and contract personnel must be free from the influence of drugs or alcohol on company premises. Implementation of the BPXA Substance Abuse Program is divided into three parts, as follows:

- **Education**. Training is available to both employees and supervisors to teach them to detect signs of abuse in themselves and the people with whom they work. Information is provided on the available rehabilitation programs.

- **Intervention**. The company has jurisdiction to perform a drug or alcohol test on employees when there is legitimate cause, such as medical surveillance following rehabilitation, or as periodic drug screening. The company makes every effort to support its employees and strongly encourages medical rehabilitation.
- **Discipline**. Upon the discovery of illicit drug use, controlled substance abuse, or alcoholic beverage possession, an employee will be subject to disciplinary action up to and including termination.

The BPXA Work Life and Employee Assistance Program (EAP) is an elemental part of rehabilitation. EAP is a confidential counseling and referral service provided free of charge to employees and their families. The EAP is provided by APS Healthcare: Work Life and Employee Assistance Program. BPXA also supports medical rehabilitation programs outside of the EAP, which are covered by the BPXA medical plan.

2.1.3 MEDICAL MONITORING [18 AAC 75.007(e)]

New BPXA employees receive an entrance physical to establish baseline health conditions. Under federal Occupational Safety and Health Administration (OSHA) and Alaska Department of Occupational Safety and Health requirements, medical monitoring is conducted as required by the type of work performed. Emergency response personnel have annual medical examinations, which include a physical exam, audiogram, respiratory exam, electrocardiogram, x-rays (when applicable), and blood work. All other BPXA employees who are field workers receive annual respiratory exams and audiograms if required to be in the company's Hearing Conservation Program (HCP) and/or the Respiratory Protection Program (RPP) by the Industrial Hygiene Team.

2.1.4 SECURITY PROGRAMS [18 AAC 75.007(f)]

(b) (7)(F), (b) (3)
[redacted]

2.1.5 FUEL TRANSFER PROCEDURES [18 AAC 75.025]

Measures are taken to prevent spills or overfilling during a transfer of oil. Loading rates are reduced at the beginning and end of a transfer, as required by 18 AAC 75.025(a). "Transfer" means oil movement between a tank and tank truck, tank vessel, or tank barge.

Each person involved in a transfer of oily fluids is capable of clearly communicating orders to stop a transfer at any time during the transfer, as required by 18 AAC 75.025(d).

A positive means is provided to stop a transfer of oily fluid in the shortest possible time, as required by 18 AAC 75.025(e).

Before beginning a transfer at an area not protected by secondary containment, the valves in the transfer system are checked to make sure they are in the correct position. Manifolds not in use are blank-flanged or capped. Transfer piping and hoses used in the transfer are checked for damage or defects before the transfer and during the transfer.

The lowermost drain and the outlets of a truck's oily fluid cargo tank are examined for leaks before the truck's tank is filled and again before the truck departs, as required by 18 AAC 75.025(g). The truck's manifold is blank-flanged or capped, and valves are secured before it leaves the transfer area. Surface liners at inlet and outlet points are the primary prevention mechanisms against discharge to the ground during the transfer of liquids.

Effective communication and planning are key factors in preventing spills. Trucks are continuously staffed during fluid transfers and transfer personnel have radios. Manual shutoff valves are available to the truck operator to stop transfers.

2.1.6 OPERATING REQUIREMENTS FOR EXPLORATION AND PRODUCTION FACILITIES [18 AAC 75.045]

Produced oil from flow tests and other drilling operations is handled in a manner to prevent spills [18 AAC 75.045(a)]. Oil produced from flow tests may be flowed directly to the plant or stored in mobile tanks.

The requirements for platform integrity inspections and isolation valves for pipelines leaving platforms do not apply [18 AAC 75.045(b) and (c)].

A typical well house is lined with an 8-foot-diameter containment sump attached to the well casing, set into the gravel pad with a seal-welded steel base. The well cellar is designed to provide secondary containment.

Catch tank requirements do not apply [18 AAC 75.045(e)].

Information pertaining to oil storage tanks and facility oil piping is found later in this Part and in Part 3.

2.1.7 LEAK DETECTION, MONITORING, AND OPERATING REQUIREMENTS FOR CRUDE OIL TRANSMISSION PIPELINES [18 AAC 75.055]

The crude oil transmission pipeline moves oil from Seal Island to Pump Station 1 of the Trans Alaska Pipeline System. See Figures B-1 and B-2 in Appendix B.

The crude oil transmission pipeline is equipped with a system capable of detecting a leak with a daily rate equal to 1 percent of daily throughput, as required by 18 AAC 75.055(a)(1). Daily throughput, for the purpose of calculating the 1 percent volume, is based on the 1-year rolling average. Flow is verified at least once every 24 hours, as required by 18 AAC 75.055(a)(2). Aerial surveillance of remote onshore pipeline segments is performed weekly, as required by 18 AAC 75.055(a)(3).

The facility's automated leak detection capability for the crude oil transmission pipeline is a meter-based system with proprietary software from Ed Farmer and Associates (EFA). Together, the meters and software provide a "mass balance line pack compensation" system called MASSPACK. The MBLPC system works by continuously measuring the amount of oil leaving and entering the pipeline, and relies on accumulating the differences among the inflow and outflow meters. Pipeline flow data are presented to the leak detection computer in 6 minute data sets, which are aggregated over time segments.

The EFA system is augmented by LEOS (Leck Erkennung und Ortangs System), which detects leaks by sampling vapors once a day. LEOS is not required to meet the leak detection standard of 1 percent of daily throughput.

The flow of incoming oil can be stopped within 1 hour after detection of a spill, as required by 18 AAC 75.055(b). If the leak detection system alarms, the control board operator proceeds through a series of steps to determine the cause of the alarm. Section 2.5.6 describes these steps in more detail. Verification of a leak would initiate pipeline shut-in. Emergency shutdown of the crude oil transmission pipeline can be activated at the Northstar control room Human-Machine Interface (HMI). Pipeline emergency shutdown will result in a complete pipeline shutdown (i.e., closure of the pipeline shutdown valves at Northstar and at the Pump Station 1 pig receiver outlet).

ADEC is notified in writing within 24 hours if a significant change occurs in, or is made to, the leak detection system and if, as a result of the change, the system no longer meets the ADEC performance requirements in 18 AAC 75.055 (18 AAC 75.475). A significant change is based on equipment or communication failure that prevents the effective functioning of the leak detection system. Transient events, such as water slugs or throughput swings, or shutdowns, are not significant changes.

Information pertaining to oil storage tanks and facility oil piping is found later in this Part and in Part 3 [18 AAC 75.055(c) through (d)].

2.1.8 OIL STORAGE TANKS [18 AAC 75.065 AND .066]

This section describes the management of ADEC-regulated tanks, i.e., oil storage tanks greater than 10,000-gallon capacity that are “in service.” In this oil discharge prevention and contingency plan (ODPCP), the term “in service” describes oil tanks that remain in regular inspection and maintenance programs. In contrast, American Petroleum Institute (API) 653 uses the term “in service” to mean storing product. Part 3 provides information for oil storage tanks greater than 10,000 gallons as required by 18 AAC 75.425(e)(3)(A).

Containers are constructed of materials compatible with the stored products. Tanks for processing drilling muds and cuttings and containers that process oil, oil with solids, and oily solids are not oil storage tanks.

INSPECTIONS

Oil storage tanks greater than 10,000 gallons, in service, and on BPXA leases are maintained and inspected consistent with API Standard 653, third edition 2001, and Addendum 1, September 2003, or API Recommended Practice 12R1, fifth edition 1997.

Inspection intervals for field-constructed tanks are not based on similar service, as outlined in API 653. However, a tank’s inspection interval may be risk-based, as outlined in API 653, if the risk-based inspection assessment is submitted to ADEC for approval.

Inspections and maintenance of shop-fabricated tanks follow Steel Tank Institute (STI) SP001 or API 653 or another equivalent approved by ADEC. Inspection intervals for shop-built tanks may be based on similar service and risk-based inspection procedures outlined in API 653. Shop-fabricated tanks are listed in Appendix A.

Inspection results and corrective action descriptions of field-constructed oil storage tanks greater than 10,000 gallons are kept for the service life of the tanks, except API 653 walk-around inspections that are kept for 5 years. Records of inspections, tests, maintenance, and repairs of shop-built ADEC-regulated tanks are kept for 5 years. Copies of these records are provided to ADEC upon request.

NOTIFICATIONS AND SERVICE STATUS

BPXA's Corrosion, Inspection and Chemicals (CIC) group follows its written procedure to notify ADEC before a BPXA-owned field-constructed oil storage tank greater than 10,000 gallons and on a BPXA lease undergoes "major repair" or "major alteration" as defined in API 653, Section 12.3.1.2, and again before the tank is filled [18 AAC 75.065(e)].

A field-constructed oil tank greater than 10,000-gallon capacity that has been removed from a maintenance and inspection program required by 18 AAC 75.065 for more than 1 year is made free of accumulated oil, marked with the words "Out of Service" and the date taken out of service, secured to prevent unauthorized use, and blank-flanged or disconnected from facility piping. BPXA notifies ADEC when those tasks are complete.

Similar notices reflecting repair and removal from service are not required for shop-built tanks.

CONSTRUCTION

Internal steam heating coils are designed to control leakage through defects, as required by 18 AAC 75.065(f).

The internal lining system in tanks T-3020 and T-6140 was installed in accordance with API RP 652, first edition 1992, as required by 18 AAC 75.065(g).

The three ADEC-regulated field-constructed tanks at Northstar were constructed and installed in 2000-2001. As required by 18 AAC 75.065(i), field-constructed oil storage tanks greater than 10,000 gallons and installed after May 14, 1992, meet the following construction standards:

- Constructed and installed in compliance with API 650, 1988 edition;
- Not of riveted or bolted construction; and
- Equipped with a leak detection system that an observer from outside the tank can use to detect leaks in the tank bottom, such as secondary catchment under the tank with a leak detection sump, or a sensitive gauging system or another leak detection system approved by ADEC.

The tanks are elevated. Cathodic protection is not required or effective because the tanks are not in contact with soil. Anodes or internal linings provide internal corrosion protection.

Shop-built ADEC-regulated oil tanks first placed in service before December 30, 2008, are not subject to an ADEC requirement for construction standards.

As required by 18 AAC 75.065(k) and .066(g), ADEC-regulated oil storage tanks greater than 10,000 gallons have one or more of the following overfill protection means:

- High liquid level alarm with signals that sound and display; or
- High liquid level automatic pump shutoff device; or
- A means to immediately determine the tank's liquid level, including close monitoring of the liquid level during a transfer to the tank; or
- Another system approved by ADEC that notifies the operator of high liquid level.

OVERFILL PROTECTION DEVICE INSPECTIONS

Overfill protection devices on ADEC-regulated tanks are tested before each transfer to them, or monthly, whichever is less frequent.

A test of the overfill protection device is a manipulation of part of the system for the purpose of eliciting a response. Devices are tested in a variety of ways depending on how they are used and frequency of use. Overfill protection devices are tested by any of the following: level transmitter calibration, level transmitter calibration with annunciation of the alarm, level transmitter calibration with annunciation of the alarm and strapping, testing the level indicators and alarms by lowering the high liquid level alarm set point to below the actual liquid level to force a false alarm, checking the circuit continuity, changing the level in the tank to verify the level transmitter or alarm enunciator, strapping to calibrate the continuous level indicator in the control room, and comparing sight glasses to a measured volume. Some methods are part of regular preventative maintenance procedures.

2.1.9 SECONDARY CONTAINMENT AREAS FOR OIL STORAGE TANKS AND TANK TRUCK LOADING AND PERMANENT UNLOADING AREAS [18 AAC 75.075]

OIL STORAGE TANKS SECONDARY CONTAINMENT

ADEC waived the requirement for secondary containment for the stationary double-wall tanks at Northstar in 2002 (waiver letter dated January 8, 2002 included at the end of this Part). The outer wall of a double-walled aboveground oil storage tank is considered secondary containment. Additional bermed, lined, secondary containment is not required.

Single-wall oil storage tanks greater than 10,000 gallons, whether field-constructed or shop-fabricated, are located within secondary containment with the capacity to hold the volume of the largest tank within the containment plus precipitation Secondary containment areas are constructed of bermed, diked, or retaining walls. The containment areas are lined with materials resistant to damage and are impermeable, as required by 18 AAC 75.075.

Shop-fabricated tanks greater than 10,000 gallons may be moved for operational needs, such as well work. For portable single-wall oil storage tanks, secondary containment is constructed to serve for the duration of their use in one location and reconstructed at further locations. For example, well service tanks typically are underlain with Herculite liner supported at the perimeter by tubular metal frames enclosing a volume 40 feet by 50 feet, and 2.5 feet high. The secondary containments for ADEC-regulated portable tanks have dimensions calculated to exceed the known capacity of the tank.

Facility personnel visually check for the presence of oil leaks or spills within secondary containments for single-wall ADEC-regulated oil storage tanks daily. The containments are further inspected weekly for debris and vegetation, proper alignment and operations of drain valves, visible signs of oil leaks or spills, and defects or failures (e.g., tears and holes). The records of daily and weekly inspections are entered weekly. “Weekly” means once in a calendar week, Sunday morning through Saturday night.

Double-wall tanks holding oil and not required to have further secondary containment are inspected monthly for oil leaks into the annulus. See Table 2-7 for visual inspection requirements. Open-top double-wall tanks will have lids in place when in operation (i.e., holding oil) and outside of additional sufficiently impermeable secondary containment.

Snowmelt runoff, debris, and accumulated rainwater are vacuumed out, or dewatered, and disposed of through the waste handling procedure.

Shop-fabricated oil storage tanks that are temporarily not in use and operationally empty are stacked without secondary containment in designated storage areas on the gravel pads. The stored tanks remain subject to integrity inspections according to the BPXA tank integrity management program. However, monthly API 653 visual inspections are conducted and documented only during months when the tanks are in active oil service.

BPXA notifies ADEC in writing within 24 hours if a significant change occurs in, or is made to, an ADEC-regulated secondary containment system and if, as a result of the change, the system no longer meets the ADEC performance requirement [18 AAC 75.475(d)].

TANK TRUCK LOADING AND PERMANENT UNLOADING AREAS

ADEC-regulated tank truck loading and permanent unloading areas are those involving frequent transfers of oil to and from ADEC-regulated tanks. Truck sites with infrequent use, seasonal use, for temporary projects or emergency generators, solely for tank maintenance, or serving non-ADEC regulated tanks are not regulated tank truck loading and permanent unloading areas. Northstar’s ADEC-regulated tank truck loading and permanent unloading area is located adjacent to Tank T-S3-8202 and is described in Table 3-1.

The tank truck loading and permanent unloading area meets the requirements of 18 AAC 75.075(g) by several means. It has a secondary containment designed to contain the maximum capacity (i.e., gross volume) of the largest single compartment of the tank trucks using the containment area. The secondary containment structure is lined with sufficiently impermeable material.

The tank truck loading and permanent unloading area is maintained free of debris, vegetation, excessive accumulated water, or other materials or conditions that interfere with the effectiveness of the system. The area has warning signs to prevent premature vehicular movement.

The tank truck loading and permanent unloading area is visually inspected before transfers, or at least monthly, whichever is less frequent (see Table 2-7).

2.1.10 FACILITY OIL PIPING [18 AAC 75.080]

This section addresses oil facility piping, which originates from or terminates at an ADEC-regulated oil storage tank or an exploration or production well. At Northstar, facility oil piping includes piping associated with the ADEC-regulated oil storage tanks, and well lines from the wellhead to the first flange in the processing facility. The crude oil transmission pipeline and the gas line which run from Northstar to Pump Station 1 are not facility oil piping. Flow lines are not present at Northstar.

Table 2-1 describes how facility oil piping complies with 18 AAC 75.080.

TABLE 2-1: FACILITY OIL PIPING COMPLIANCE

CITATION 18 AAC 75.080	REGULATORY STANDARD	ADEC-REQUIRED ENGINEERING STANDARD	HOW THE STANDARD IS MET
(b)	Maintain metallic facility oil piping in accordance with a corrosion control program.	None	Corrosion control of facility piping is guided by BPXA internal procedures
(c)	Facility oil piping placed in service after December 30, 2008 is designed and constructed in accordance with …ASME B31.3-2004 … ASME B31.4-2002 … or ASME B31.8-2003	ASME B31.3 – 2004 ASME B31.4 – 2003 ASME B31.8 – 2003	BPXA internal guidance stipulates design procedures consistent with the standard.
(d)	Buried metallic facility oil piping placed in service between May 14, 1992 and December 30, 2008, is protected from corrosion by installing protective coating and cathodic protection appropriate for local soil conditions and is of all welded construction with no clamped, threaded, or similar connections for lines larger than a one inch nominal pipe size.	None	Northstar has no buried facility piping.
(e)	Buried facility oil piping placed in service after December 30, 2008, is of all welded construction with no clamped, threaded, or similar connections for lines larger than one inch nominal pipe size; and Unless constructed of a corrosion-resistant material approved by the department is protected from corrosion by installing protective coating; and cathodically protected.	None	Northstar has no buried facility piping.
(f)	Cathodic protection systems installed after 2008 meet NACE RP0169-2002, designed by a corrosion expert, and installation supervised by a corrosion expert.	NACE RP0169 – 2002	No equipment is subject to the requirement.
(g)	If a piping segment of a buried facility oil piping installation is exposed for any reason, the segment is carefully examined, for damaged coating or corroded piping in accordance with Section 9.2.6 of …API 570 …If active corrosion is found during that examination, the owner or operator shall implement actions for control of future corrosion; and significant repairs or replacements must meet the requirements of ADEC's 18 AAC 75.080] (c) and (e)	API 570*, Section 9.2.6	Northstar has no buried facility piping.
(h)	Buried facility oil piping installation of metallic construction without cathodic protection shall ensure that the piping is electrically inspected by a corrosion expert for active corrosion at least once every three years, but with intervals between inspections not exceeding 39 months; and in areas in which active corrosion is found, cathodically protected.	None	No equipment is subject to the requirement.

TABLE 2-1 (CONTINUED): FACILITY OIL PIPING COMPLIANCE

CITATION 18 AAC 75.080	REGULATORY STANDARD	ADEC-REQUIRED ENGINEERING STANDARD	HOW THE STANDARD IS MET
(i)	Aboveground facility oil piping is supported consistent with the requirements of Paragraph 321 of …ASME B31.3-2004.	ASME B31.3 – 2004	Aboveground facility piping support design is consistent with the requirements of the ASME code used to design the piping.
(j)	Facility oil piping is maintained and inspected under a program developed in accordance with API 570 or another equivalent program approved by the department.	API 570*	Inspection and repair practices are in accordance with API 570 or an alternative approved by ADEC.
(k)	Cathodic protection systems consistent with NACE RP0169, Section 10, survey, maintain test leads.	NACE RP0169, Section 10	No equipment is subject to this requirement.
(l)	Aboveground facility piping … is protected from atmospheric corrosion by … protective coating … use of corrosion-resistance material … or … demonstrate …by…experience… that atmospheric corrosion of GPB facility piping…does not affect the safe operation of the piping before the next scheduled inspection.	None	Experience shows that atmospheric corrosion of aboveground facility oil piping does not affect safe operation between inspections.
(m)	At a soil-to-air interface, piping is protected against external corrosion through the application of a protective coating or …corrosion-resistant materials.	None	No equipment is subject to this requirement.
(n)	Aboveground facility oil piping and valves must ensure that the piping and valves are visually checked for leaks or damage during routine operations or at least monthly, and appropriately protected from damage by vehicles.	None	BPXA procedures call for regular visual inspection of pipelines. Traffic barriers are in place where appropriate.
(o)	Facility oil piping that is removed from service for more than one year shall [be] free of accumulated oil, identified as to origin, marked on the exterior with the words "Out of Service" and the date taken out of service, secured in a manner to prevent unauthorized use, and either blank flanged or otherwise isolated from the system. Notify the department when facility oil piping is removed from service and when the actions required…are completed. Removed from service means the pipe is not used for its intended purpose of moving oil and is no longer maintained or inspected per API 570.	None	Facility piping removed from service for more than one year is free of accumulated oil, identified as to origin, marked with the words “Out of Service” or “Removed from Service” and the date taken out of service, secured to prevent un-authorized use, and blank-flanged or isolated from the system. Notifications of the out-of-service status are made by way of BPXA Pipeline group reports to ADEC SPAR IPP.

* API 570, Second Edition, October 1998, Addendum 1, February 2000, Addendum 2, December 2001, and Addendum 3, August 2003.

The applied corrosion control measures reflect the active or potential corrosion mechanisms in the relevant system. For Northstar's pipeline network, these can be broadly sub-divided into internal and external corrosion mechanisms.

INTERNAL CORROSION AND EROSION OF THE PRODUCTION SYSTEM

The production system transports multiphase oil, water, and gas. The properties of fluids are similar throughout the system, although temperature, pressure, and velocity vary through the system. Water cut, gas-to-oil ratio, and solids content vary from line to line. Table 2-2 summarizes the significant corrosion mechanisms relevant to this system. For clarity, all corrosion threats are considered in the table; however, only the high severity threats are discussed in detail.

TABLE 2-2: INTERNAL CORROSION MECHANISMS RELEVANT TO PRODUCTION SYSTEM

CORROSION MECHANISM	SEVERITY OF MECHANISM	CONTROL METHOD
Carbon dioxide corrosion	High	Chemical inh bition
Flow-assisted corrosion	High	Chemical inh bition Velocity control
Solid erosion and erosion-corrosion	High	Velocity control Well put-on-production procedures Solids monitoring
Preferential weld corrosion	High	Chemical inh bition Fabrication control
Chemical attack	High	Chemical selection Operating procedures Equipment design
Microbiologically influenced corrosion (MIC)	Low	Chemical inh bition
Under-deposit / crevice corrosion	Low	Velocity control
Galvanic corrosion	Low	Material selection Material isolation
Hydrogen sulfide (H_2S) corrosion	Low	Chemical inh bition
Oxygen corrosion	Low	Mechanical deaeration Chemical deaeration

Carbon dioxide corrosion is the primary corrosion mechanism in the production system. The control of carbon dioxide corrosion is achieved via chemical injection. Corrosion inhibitor is injected into the individual wellheads on a continuous basis. The chemical treatment volumes are based on the water production of the well and the corrosivity of the fluids based on corrosion monitoring. Preferential weld corrosion can be exacerbated by carbon dioxide but is primarily due to improper welding technique. Corrosion control is the same as for carbon dioxide.

Flow-assisted corrosion is controlled via chemical inhibition, as discussed under carbon dioxide corrosion and velocity control. Erosion and erosion-corrosion are due primarily to solids produced from wells, and this may be exacerbated during times when putting the well on production. Control is generally through put-on-production procedures and velocity control.

Chemical attack has been associated with corrosive inhibitor (corrosion or scale) pooling in production pipework during shut-ins. There have also been instances of injection quill failure, leading to contact of the neat (pure) chemical with the pipewall during normal operations. Chemical attack is controlled via the use of a lower corrosivity scale inhibitor and improved operating procedures that shut off the chemical supply during shut-ins. The injection quill problem has been overcome by specifying heavier wall quills.

MIC, under deposit galvanic, H_2S and oxygen corrosion are considered to be of low to negligent severity in the Northstar production system.

INTERNAL CORROSION OF THE DISPOSAL WATER SYSTEM

The disposal water injection system is defined as starting at the water outlets off the separation vessels and ending at the disposal formation. It therefore includes the process piping, storage tanks, injection pumps, headers, and well lines that store or transport produced water and the disposal wells.

Table 2-3 summarizes the significant external corrosion mechanisms relevant to this system. For clarity, all corrosion threats are considered in the table; however, only the medium- and high-severity mechanisms are discussed in detail.

TABLE 2-3: INTERNAL CORROSION MECHANISMS RELEVANT TO DISPOSAL WATER INJECTION SYSTEM

CORROSION MECHANISM	SEVERITY OF MECHANISM	CONTROL METHOD
Carbon dioxide corrosion	Low	Chemical inhibition
Flow-assisted corrosion	Low	Chemical inhibition Velocity control
Solid erosion and erosion-corrosion	Low	Velocity control Well put-on-production procedure Solids monitoring
Preferential weld corrosion	Low	Chemical inhibition Fabrication control
Chemical attack	Medium	Chemical selection Operating procedures Equipment design
MIC	Medium	Chemical inhibition
Under-deposit / crevice corrosion	Medium	Velocity control
Galvanic corrosion	Low	Material selection Material isolation
H_2S corrosion	Low	Chemical inhibition
Oxygen corrosion	High/Low	Mechanical deaeration Chemical deaeration

As the oil stabilization process reduces the vast majority of the carbon dioxide and its partial pressure, the severity of carbon dioxide corrosion is reduced further in the disposal water system. The carbon dioxide corrosion inhibitor is dosed at individual well lines to control corrosion at the higher partial pressure; therefore, the residual carry-over into the disposal water system is capable of providing additional inhibition in controlling carbon dioxide corrosion.

MIC is an issue in disposal water systems because the low fluid velocities in tanks and pipework allow bacteria colonies to become established and thrive. The current three-phase corrosion inhibitor is known to be toxic to sulfate-reducing bacteria and general anaerobic bacteria.

Oxygen may be introduced into the water disposal system via addition of wastewater from the effluent system. Oxygen scavenger has been utilized to lower the amount of oxygen in the system.

Chemical attack relates to the injection of surfactant and is managed in a manner similar to the production system.

INTERNAL CORROSION CONTROL

Corrosion monitoring and mitigation tools may include corrosion inhibitors, biocides, oxygen scavengers, corrosion weight loss coupons, electrical resistance probes, non-destructive examination inspection techniques, smart pigs, visual inspections, Kinley caliper surveys, monitoring of process flow conditions, and bioprobes.

EXTERNAL CORROSION CONTROL

There is no buried facility piping at the Northstar facility.

Aboveground oil facility piping subject to atmospheric corrosion is visually inspected every 3 years, not to exceed 39 months.

CORROSION MONITORING

Northstar uses the corrosion monitoring data to manage the corrosion control programs.

The corrosion monitoring programs generate data from corrosion probes, weight loss coupons, and inspection. Each type of data has its benefits and limitations; therefore, the data from corrosion probes, coupons, and inspection are viewed as complimentary and are used in concert in managing the corrosion control programs. The monitoring techniques together with process data allow a clear picture of corrosion activity in the equipment.

Data are generated throughout the year and new data are reviewed periodically. Each type of data has a corresponding target limit. If target value is exceeded, the cause is investigated and, if appropriate, mitigating action is taken. In addition to the periodic reviews of current data, more in-depth reviews are made looking for broader changes or trends.

The data from the corrosion control, monitoring, and inspection programs are managed with an electronic database. It stores and allows analysis of current and historical data.

EXTERNAL/INTERNAL CORROSION INSPECTION ACTIVITIES

Inspection Intervals

Many factors determine the interval between successive inspections or which inspection will be performed. The overriding factor in determining inspection intervals is the purpose of inspection. The internal inspection program is subdivided into four elements, each with a separate purpose and frequency of inspection. The external inspection program has one element. Smart pigging is used to support both the internal and external inspection programs.

The terms “internal” and “external” inspections describe the purpose of the inspection, i.e. looking for internal or external corrosion, not the inspection method. With the exception of smart pigging, inspections are performed external to the equipment. The scope of the inspection program, once established, is relatively constant and includes plant inspections.

Corrosion Rate Monitoring

The goal of the corrosion rate monitoring program is to detect active corrosion in support of corrosion control activities, primarily the chemical inhibition program. The data are complementary to other monitoring data, such as corrosion probes and corrosion coupons. Because the primary aim is to determine when corrosion occurs, this program is of fixed scope at fixed inspection intervals.

Erosion Rate Monitoring

The purpose of the erosion rate monitoring program is similar to the corrosion rate monitoring, but is aimed at monitoring erosion activity. Production variables are the driving factor for this damage mechanism (i.e., production rates and solids loading); therefore, inspection is determined by “triggers” such as velocity limits, well work, etc. If such triggers are exceeded, inspections are performed on a daily, weekly, or monthly basis depending on the driving factors for placing the equipment in a potential high-risk state. Inspections are continued until confidence is gained that erosion is not occurring. The erosion rate monitoring program is primarily associated with three-phase well lines.

Frequent Inspection Program

The aim of the frequent inspection program is to manage mechanical integrity at locations where significant corrosion damage has been detected. Locations are added to the frequent inspection program if they are approaching repair, derate criteria, or if unusually high corrosion or erosion rates are detected. Inspections are performed frequently until the item is repaired, replaced, derated, taken out of service, or corrosion/erosion rates reduce. The inspection interval varies, depending on how close the location is to repair/derate and the rate of corrosion, but does not exceed 1 year.

Comprehensive Integrity Program

The comprehensive integrity program is an annual program aimed at detecting new corrosion mechanisms and new locations of corrosion and monitoring damage at known locations. This program provides an assessment of the extent of degradation and the fitness for service. Equipment is covered by the comprehensive integrity program, although not all equipment is inspected annually.

Corrosion Under Insulation

A recurring screening program has been determined to be the best measure to identify equipment at risk. Prioritization of inspection surveys is determined by average temperature of the equipment, age of equipment, and/or the last time a complete screening process was completed. If screening has been completed or once screening is completed, sites are revisited at intervals described in Table 2-4. As a result of findings from the screening process, the extent of additional examination is determined. Well lines are covered by the corrosion under insulation program.

TABLE 2-4: RECURRING FREQUENCY OF CORROSION UNDER INSULATION INSPECTION SURVEYS

EQUIPMENT TEMPERATURE	INTERVAL BETWEEN EXAMINATIONS (YEARS)
≤80 degrees Fahrenheit (F)	10
>80 -120 F	8
>120 - 150 F	6
>150 F	4

Cased Piping Inspection

Cased facility oil piping is not present at Northstar.

OUT-OF-SERVICE PIPING REQUIREMENTS

Facility piping removed from service for more than 1 year is free of accumulated oil, identified as to origin, marked with the words “Out of Service” and the date taken out of service, secured to prevent un-authorized use, and blank-flanged or isolated from the system.

The out-of-service notices to ADEC are made within 1 year after the tasks to remove facility piping from service are completed. “Removed from service” means the pipe is not in regular use for its intended service (i.e., hydrocarbon service) and no longer in a regular maintenance and inspection program required by ADEC.

TEMPORARY PIPING

Temporary hardline piping is used for intermittent well testing. It does not meet the definition of facility piping in 18 AAC 75.990(171) and is not subject to ADEC regulations.

2.2 DISCHARGE HISTORY [18 AAC 75.425(e)(2)(B)]

The discharge history of reported Northstar oil spills greater than 55 gallons, and oil spills of any volume to water or tundra, for the period January 2001 through December 2010 is provided in Appendix C and includes the following information:

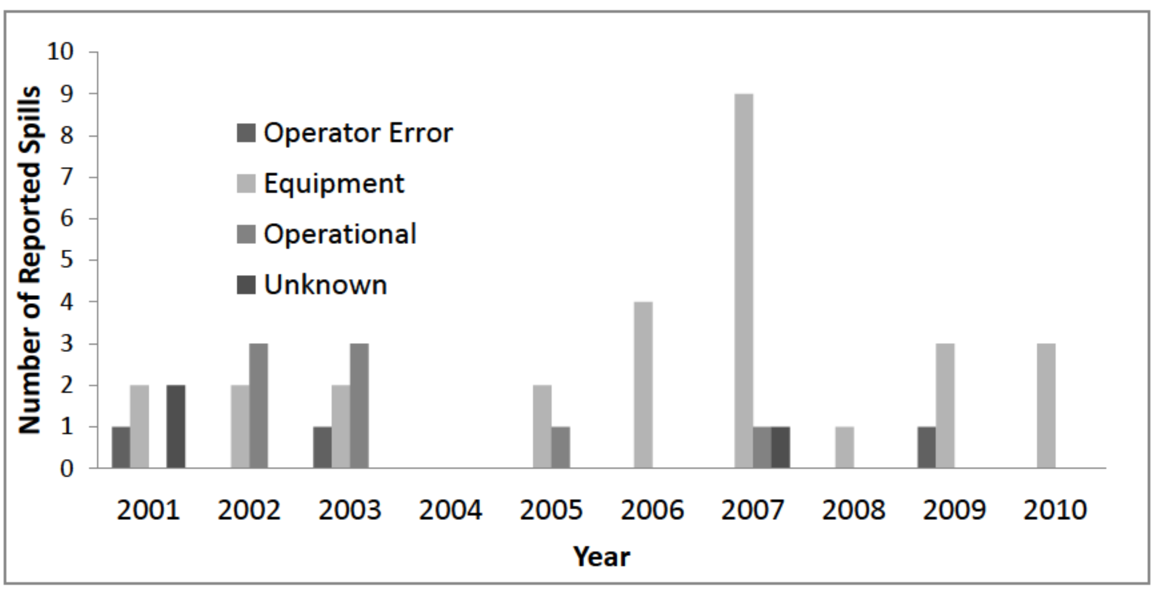
- Date of discharge,
- Material discharged,
- Estimated amount discharged,
- Description of the spill event,
- Environmental impact, and
- Corrective and preventive actions taken.

Spills to sea ice or the ice road to Seal Island are considered spills to water.

The history of reported discharges of volumes greater than 55 gallons is maintained in the BPXA spill database for the life of the facility.

Figure 2-1 shows the annual number of reported spills. Three spills of unknown cause are associated with “mystery” sheens and drips.

FIGURE 2-1: REPORTED NORTHSTAR OIL SPILLS 2001-2010



2.3 POTENTIAL DISCHARGE ANALYSIS [18 AAC 75.425(e)(2)(C)]

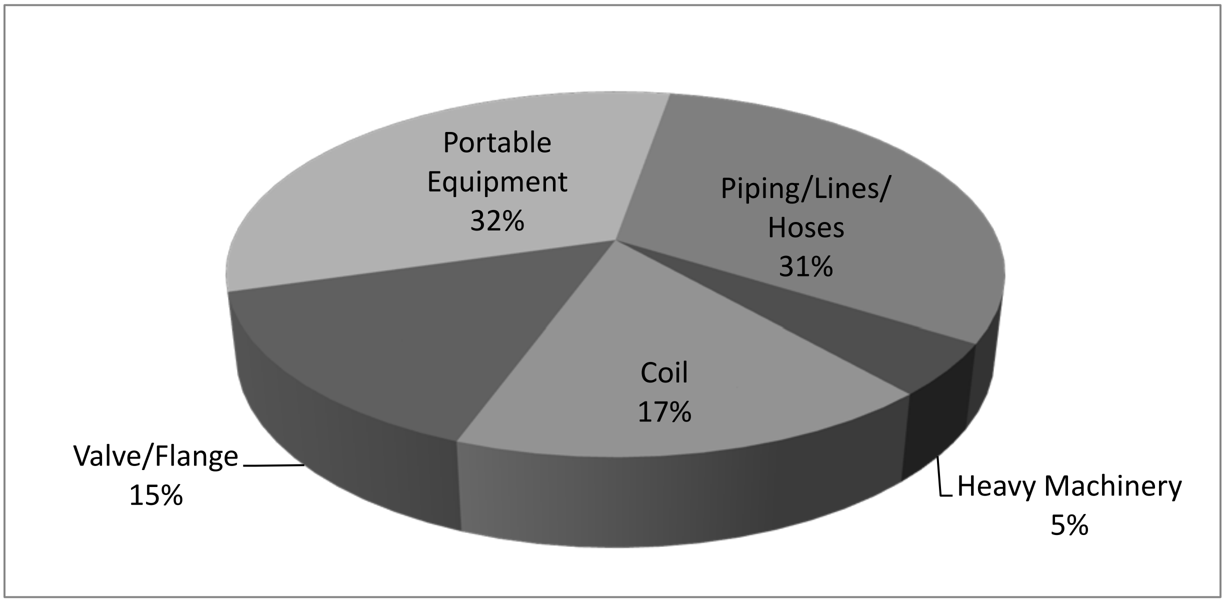
The potential for oil spills is understood from historical spill data. Table 2-5 summarizes the spill history in Appendix C (reported oil spills greater than 55 gallons, and spills of any volume to water or tundra, for the period January 2001 through December 2010). The historical data assist in identifying operations or equipment prone to spills.

Spills associated with equipment problems make the largest category of reported spills by volume (56 percent), followed by operational activities (39 percent), and operator error (5 percent). Figure 2-2 depicts the percentage of estimated volumes spilled associated with equipment.

TABLE 2-5: NORTHSTAR OIL SPILL REPORTS, 2001-2010

CATEGORY	SOURCE	NUMBER OF SPILLS REPORTED	ESTIMATED CUMULATIVE VOLUME (GALLONS)
Equipment	Valve/Flange	3	184
	Portable Equipment	2	397
	Piping/Line/Hose	4	384
	Heavy Machinery	18	57
	Coil	1	210
Operator Error	Driving/Operating	2	110
	Fluid Transfer	1	<1
Operational	Well	2	855
	Flare	6	<3
Unknown	Sheens/drips from unknown source	3	<4

FIGURE 2-2: REPORTED NORTHSTAR SPILLS ASSOCIATED WITH EQUIPMENT (ESTIMATED PERCENTAGE OF TOTAL VOLUME)



An overflow at a portable diesel storage tank contributed 15 percent (322 gallons) of the total volume spilled at Northstar. Two diesel releases into well cellars (420 gallons and 435 gallons) each contributed approximately 18 percent of the total volume spilled at Northstar. Remaining reported spills (47 percent) had a total discharge volume of 1,026 gallons.

Potential and past spills are discussed during the Authorization to Proceed (ATP) process while analyzing job hazards. Environmental advisors attend project kickoff and operations support meetings where spill mitigation measures and reporting procedures are discussed. Environmental advisors also work with responsible parties to ensure timely and accurate reporting and clean up of spills. Oil spill causes are shared throughout the facility and other BPXA facilities.

Simulated examples of potential oil spills are presented in Table 2-6.

TABLE 2-6: POTENTIAL OIL DISCHARGES FROM MAJOR SOURCES

SOURCE	SIZE	CAUSE	DURATION	PREVENTATIVE MEASURES
Diesel transfer from tank truck	30 gallons	Tank overfill	30 seconds	Transfer procedures in place; secondary containment
Diesel transfer from barge to diesel tank	440 to 880 gallons	Hose rupture	1 to 2 minutes	Transfer procedures in place; secondary containment; hose watch
Diesel Tank	2,800 barrels	Tank rupture	Instant	Secondary containment; tank inspection program
Crude Oil Pipeline	184 bopd	Leak below detection limits	7 to 60 days	Engineering design; dual leak detection systems; smart pig analysis
Crude Oil Blowout	2,295 bopd	Uncontrolled flow from wellbore	1 to 15 days	Blowout prevention equipment; well houses; subsurface safety valves

Spill prevention actions involve training, operating procedures, leak detection, inspections, and secondary containment outlined in Part 2. Northstar participates proactively in spill prevention programs including campaigns, investigations, and training to increase employee awareness levels.

BPXA North Slope operations employ multiple learning processes as part of the Alaska Incident Investigation program to help prevent potential discharges. Proven techniques, such as “Root Cause Failure Analysis,” are utilized during the investigation process to ensure the highest value actions are implemented to prevent reoccurrence. Lessons learned are broadly shared across BPXA and the contractor community to promote spill prevention. Depending on the incident, the review team may include personnel responsible for the operation causing the spill, their foreman or supervisor, a safety representative, field environmental compliance personnel, a facility supervisor, and/or a corrosion engineer. The investigation process is aimed at addressing the root cause of the incident and thereby eliminating workplace risk, reducing personnel exposure to spilled materials, preventing reoccurrence of spills, and identifying additional early detection opportunities. Spill investigation results are communicated to BPXA and contractor field personnel to promote spill prevention. Periodically, teams are developed to conduct an analysis of potential trends in spill causes, locations, materials, volumes, and frequencies. The analysis of these trends offers the opportunity to proactively implement additional continual improvement measures to further reduce the potential for discharge.

2.4 CONDITIONS INCREASING RISK OF DISCHARGE [18 AAC 75.425(e)(2)(D)]

Conditions specific to BPXA's North Slope operations that potentially increase the risk of an oil spill, and actions taken to reduce the risk of a spill, are as follows:

- Heat may cause gases to expand, increasing the likelihood of discharge. North Slope facilities are engineered to accommodate temperature fluctuations.
- Cold snaps present obvious threats to field operations. North Slope facilities are engineered to withstand arctic conditions.
- Icy roads, white-out conditions, and changes in traffic patterns may increase the risk of vehicle collisions. BPXA Security's strict adherence to vehicle safety, speed limits, and the posting of warning signs or traffic cones helps to minimize the potential for vehicular accidents that may result in a spill.

(b) (3), (b) (7)(F) [redacted]

- High winds could increase the risk of discharge during fuel transfers, particularly during barge-to-tank transfers. If wind speed appears to pose a threat to communications or hoses and booming, transfer operations will be postponed until the wind subsides.
- As the fields age, the discharge potential increases. To minimize spills related to aging facilities, BPXA uses a computerized preventative maintenance program, has a corrosion control program, does valve inspections in accordance with Alaska Oil and Gas Conservation Commission (AOGCC) regulations, has leak detection monitoring, and conducts regular visual inspections.
- High water and/or ice during break-up could increase the risk of discharge over river crossings. The pipeline support members have been designed to withstand ice conditions expected at the river crossings.

Conditions specific to BPXA Northstar operations that potentially increase the risk of discharge and actions taken to eliminate or minimize identified risks are as follows:

- To minimize the risk of subsea leaks, the crude oil transmission pipeline has more than 2.5 times the minimum wall thickness required for internal pressure containment. The line also is designed with no flanges, valves, or fittings in the subsea section. Leak detection systems are described in Section 2.5.6.
- Northstar Production Island is susceptible to storm surges due to its location in the Beaufort Sea. The design for the island includes a submerged gravel berm on the west, north, and east sides of the island. The berm causes premature breaking of incoming waves and reduces wave force and overtopping. The design also reduces the impact of multi-year ice floes.
- Ice pounding and ice strudel scour could threaten the offshore pipelines by causing soil displacement below the lowest point of ice contact with the seabed. Strudel scours typically occur

near river deltas where river overflooding of nearshore ice sheets may occur during spring. The river overflood typically flows through vertical cracks or flow holes within the ice sheets and causes scouring of the seabed directly below. To protect against these forces, offshore pipelines are buried in a 7-foot to 8-foot trench. The Northstar pipelines are located at a sufficient depth so that ASME/American National Standards Institute (ANSI) elastic pipeline stress limits are not exceeded by the formation of pipeline spans caused by 100-year annual return period strudel scour dimensions. The pipelines are at sufficient depth to avoid ice contact and soil displacements that may cause pipeline strains in excess of project-specific limit-strain criteria.

- Buried arctic pipelines are installed at temperatures below their operating temperatures. Because buried pipelines are restrained during thermal expansion, significant compressive force develops, which may cause upheaval buckling (i.e., vertical buckling displacement of a pipeline due to low lateral stability provided by the overlying soil). The Northstar pipelines are located at sufficient depth to avoid upheaval buckling.
- High water and/or ice during break-up could increase the risk of discharge over river crossings. The Northstar pipeline has one aboveground crossing at the Putuligayuk River. The crossing is designed to resist the impact forces of ice at break-up and high water.
- The weight and heat from a buried operating pipeline causes some differential thaw subsidence in permafrost soils. Permafrost soils are found in the nearshore area of the Northstar pipeline route.

2.5 DISCHARGE DETECTION [18 AAC 75.425(e)(2)(E)]

2.5.1 DISCHARGE DETECTION FOR DRILLING OPERATIONS

A drilling rig is not present at Northstar.

2.5.2 DISCHARGE DETECTION FOR WELLS

[redacted]

2.5.3 PRODUCTION HEADER DISCHARGE DETECTION

The primary leak detection method for the production header is visual inspection. In addition to inspection, the header has pressure switches to detect low line pressure caused by a catastrophic line rupture. [redacted]

2.5.4 AUTOMATED METHODS OF DISCHARGE DETECTION

[redacted]

2.5.5 DISCHARGE DETECTION FOR OIL STORAGE TANKS

[redacted]

(b) (3), (b) (7)(F)

[redacted]

2.5.6 CRUDE OIL TRANSMISSION PIPELINE DISCHARGE DETECTION

(b) (3), (b) (7)(F)

[redacted]

(b) (3), (b) (7)(F)

[redacted]

(b) (3), (b) (7)(F)

[redacted]

(b) (3), (b) (7)(F)

[redacted]

2.5.7 VISUAL INSPECTIONS FOR DISCHARGE DETECTION

Table 2-7 summarizes the visual inspections performed on regulated equipment.

TABLE 2-7: VISUAL SURVEILLANCE SCHEDULE

EQUIPMENT	RESPONSIBLE POSITION	REGULATING AGENCY	INSPECTION	FREQUENCY	REGULATORY CITATION	RECORD KEEPING
Oil storage tanks >10,000 gallons	Northstar Multi Task Technician (MTT)	ADEC	Visual inspection of external conditions of storage tanks	Monthly	18 AAC 75.065 and .066 following API 653	PRIDE or Figure A in BPXA's *Criteria for Tank Integrity Management Program* (CRT-AK-06-96); retain for 5 years
Secondary containment serving oil storage tanks >10,000 gallons	Northstar MTT	ADEC	Visual inspection for oil leaks, spills, defects and debris	Daily for leaks or spills without record, unless precluded by safety or weather Weekly with record for leaks or spills, defects, and interference by debris or vegetation, unless precluded by safety or weather	18 AAC 75.075(c)	PRIDE or Appendix B form in ADEC *Secondary Containment Inspection Procedure*; retain 5 years During Phase 2 and Phase 3 conditions, the inspection form will be noted with "Wx" or "No safe access."
		ADEC	Test controls that monitor interstitial space between inner and outer walls of the tanks	Monthly	18 AAC 75.075 See January 8, 2002 waiver.	
Secondary containment at ADEC-regulated diesel tank truck loading area	ACS Environmental Specialist	ADEC	Visual Inspection	Monthly or before each transfer, whichever is less frequent	18 AAC 75.075(g)	PRIDE or Appendix B form in ADEC *Secondary Containment Inspection Procedure*; retain 5 years
Overfill protection device on oil storage tanks >10,000 gallons	Northstar MTT	ADEC	Test overfill protection device on non-continuous flow tanks	Monthly, or before each transfer, whichever is less frequent	18 AAC 75.065(l) and .066(h)	PRIDE or Figure A in BPXA's *Criteria for Tank Integrity Management Program* (CRT-AK-06-96); retain for 5 years

TABLE 2-7: VISUAL SURVEILLANCE SCHEDULE

EQUIPMENT	RESPONSIBLE POSITION	REGULATING AGENCY	INSPECTION	FREQUENCY	REGULATORY CITATION	RECORD KEEPING
Aboveground regulated facility oil piping and valves from well through production header; to and from ADEC-regulated tanks	Northstar MTT	ADEC	Visual inspection of visible facility piping and valves for leaks and damage	Monthly	18 AAC 75.080(n)(1)	Inspection Log; retain for 5 years
Northstar Crude Oil Transmission Pipeline	Shared Services Aviation/Northstar Operations Personnel	ADEC	Aerial surveillance of crude oil transmission pipeline	Weekly on remote locations of pipeline unless precluded by safety or weather Aerial surveys of the undersea portion of the pipeline are not conducted during periods of ice coverage	18 AAC 75.055(a)(3) See June 17, 2004 waiver letter.	Inspection forms; Shared Services Aviation Logs

2.6 WAIVERS [18 AAC 75.425(e)(2)(G)]

Waivers follow this page. Waiver content is as follows:

- Wording Change for Marking Out-of-Service Facility Piping (March 26, 2009),
- Waiver of Requirement for Aerial Pipeline Surveys (June 17, 2004), and
- Waiver of Oil Storage Tank Secondary Containment Requirements (January 8, 2002).

STATE OF ALASKA

SARAH PALIN, GOVERNOR

DEPT. OF ENVIRONMENTAL CONSERVATION

DIVISION OF SPILL PREVENTION AND RESPONSE
INDUSTRY PREPAREDNESS PROGRAM
Exploration Production & Refineries

555 Cordova Street
Anchorage, AK 99501
PHONE: (907) 269-3094
FAX: (907) 269-7687
http://www.dec.state.ak.us

March 26, 2009

File No.: 305.35
(BPXA – GPB, End,
Milne, Northstar)

Ms. Mary E. Cochlan-Vendl
Pipeline Programs Coordinator
BP Exploration (Alaska) Inc.
P.O. Box 196612
Anchorage, AK 99519-6612

Subject: **BP Exploration (Alaska) Inc. (BPXA) Oil Discharge Prevention and Contingency Plans (Plans). Wording Change for Marking Facility Piping – Waiver for the Following Plans:**
Endicott/Badami, ADEC Plan No. 06-CP-4130
Greater Prudhoe Bay, ADEC Plan No. 06-CP-5079
Milne Point Unit, ADEC Plan No. 06-CP-4132
Northstar, ADEC Plan No. 06-CP-4136

Dear Ms. Cochlan-Vendl:

The Alaska Department of Environmental Conservation (ADEC) has reviewed your March 25, 2009 request for a waiver from the facility piping marking requirements in 18 AAC 75.080(o) for BPXA's North Slope facilities associated with the above-listed plans. In addition to other requirements, 18 AAC 75.080(o) specifies that facility oil piping removed from service for more than one year be marked with the words "Out of Service" and the date taken out of service. BPXA has requested our approval to use the wording "Removed From Service" rather than "Out of Service."

In accordance with 18 AAC 75.015, ADEC may waive a requirement if the owner or operator demonstrates that an equivalent level of protection will be achieved by using a technology or procedure other than that required by 18 AAC 75.005 – 18 AAC 75.085. Since ADEC considers the two phrases to be equivalent in meaning and since the wording is used interchangeably in our regulations, ADEC approves this waiver request.

If you have any question, please contact Laurie Silfven at (907) 269-7540 or me at (907) 269-3054.

Sincerely,

Betty Schorr

Betty Schorr
Program Manager

cc: Laurie Silfven, ADEC, EPR
Graham Wood, ADEC, EPR
Bob Tisserand, ADEC, EPR
Gary Evans, ADEC, EPR
Sam Saengsudham, ADEC, PTI
Ed Meggert, ADEC, PERP Fairbanks
Mike Bronson, BPXA
Glen Pomeroy, BPXA

FRANK H. MURKOWSKI, GOVERNOR

555 Cordova Street
Anchorage, AK 99501
PHONE: (907) 269-3094
FAX: (907) 269-7687
http://www.state.ak.us/dec

DEPT. OF ENVIRONMENTAL CONSERVATION
DIVISION OF SPILL PREVENTION AND RESPONSE
INDUSTRY PREPAREDNESS PROGRAM
Exploration Production & Refineries

June 17, 2004

File No: 305.40 (Northstar)

Mr. Mike Bronson
Crisis Management Coordinator
BP Exploration Alaska, Inc.
900 East Benson Blvd.
PO Box 196612
Anchorage, AK 99519-6612

Dear Mr. Bronson:

SUBJECT: BP Exploration (Alaska), Inc. Northstar Facility, Oil Discharge Prevention and Contingency Plan, ADEC Plan 014-CP-4136, Waiver of Requirement for Aerial Pipeline Surveys.

The Alaska Department of Environmental Conservation (ADEC) has reviewed your request to have the aerial survey requirement of 18 AAC 75.055(a)(3) waived for the Northstar crude oil transmission pipeline. In accordance with 18 AAC 75.015, ADEC may waive a leak detection requirement if the owner or operator demonstrates that an equivalent level of protection will be achieved by using a technology or procedure other than that required by 18 AAC 75.005 – 18AAC 75.090. [18AAC 75.015]

Due to the impracticality of conducting aerial surveys, as required by 18AAC 75.055(a)(3), of the undersea portion of the Northstar crude oil transmission pipeline during periods of ice coverage, BP (Alaska) has been conducting through-ice surveys for the purpose of detecting and locating hydrocarbon leaks. The need for these through-ice surveys is negated by the recent installation and use of the LEOS leak detection system, which provides an even greater level of leak location detection.

Based on the information provided by BP in your letters of May 14, 2004 and June 14, 2004, and our visual verification of the ability of the LEOS systems to detect small leaks from the undersea pipeline, the ADEC is granting a waiver of the requirements of 18 AAC 75.055(a)(3) for the Northstar Pipeline to allow the use of the LEOS leak detection system in lieu of conducting aerial surveys during periods of ice coverage. The waiver is subject to the following conditions:

1) During the ice cover season, the LEOS system is consistently operated and maintained as per the manufacturer's specifications.

2) The LEOS system is tested annually, prior to ice freeze up, to verify its sensitivity and accuracy in determining leak locations. A report summarizing the test results must be submitted to ADEC within 30 days following the test.

3) In the event that the LEOS system is found to be operating improperly, during the required operating period, notification should be made to the department as soon as practicable. Notification should include the estimated time that the system will be unavailable and a brief proposal outlining the actions that BP will take to ensure the continuation of routine leak detection monitoring.

4) Section 2.1.8 of the plan must be amended to include reference to the use of the LEOS leak detection system, in lieu of aerial surveillance during periods of ice coverage.

5) The Northstar contingency plan must be revised at the next routine update to include this waiver approval information in the plan.

Please be advised that the approval of this waiver does not relieve you of the responsibility for securing other state, federal or local approvals or permits, and that you are still required to comply with all other applicable laws.

If you have any questions, please contact Wade Gilpin at 269-3060 or me at 269-7680.

Sincerely,

Lydia Miner

Lydia Miner
Section Manager

cc: Bill Hutmacher, ADEC
Wade Gilpin, ADEC
Sam Saengsudham, ADEC
Ed Meggert, ADEC
Rex Okakok, North Slope Borough
Sam Means, ADNR
Al Ott, ADF&G
Carl Lautenberger, USEPA
Christy Bohl, MMS
Capt. Ron Morris, USCG MSO-Anchorage
Jim Taylor, USDOT-RSPA

STATE OF ALASKA

DEPT. OF ENVIRONMENTAL CONSERVATION
DIVISION OF SPILL PREVENTION AND RESPONSE
INDUSTRY PREPAREDNESS AND PIPELINE PROGRAM

TONY KNOWLES, GOVERNOR
555 Cordova Street
Anchorage, AK 99501
Phone: (907) 269-3094
Fax: (907) 269-7687
http://www.state.ak.us/dec

January 8, 2002

File No. 305.30.4136

Mr. Nick Glover
BP Exploration (Alaska), Inc.
P.O. Box 196612
Anchorage, Alaska 99519-6612

Dear Mr. Glover:

Subject: Request for Waiver of Secondary Containment Requirements, BP Exploration (Alaska), Inc. Northstar Operations, ADEC Plan Number 984-CP-4136

The Alaska Department of Environmental Conservation (ADEC) has reviewed your September 18, 2001 request for a waiver from the secondary containment requirements of 18 AAC 75.075(a) for a diesel tank (2,800 bbls), produced water overflow tank (1,000 bbls), and a well cleanout tank (500 bbls).

According to the information provided, the tanks are

- Elevated on steel platforms;
- Constructed and inspected in accordance with API 650 and 653 standards;
- Built with double-wall and double-bottom construction, providing impermeable secondary containment; and
- Equipped with automated liquid level determination, overflow protection, and leak detection within the secondary containment.

ADEC engineers have calculated the volume of the secondary containment to be 10-15% of the total volume of the inner tank. While this falls short of the 110% indicated in the waiver request letter, this should be sufficient. If the inner tank leaked, the volumes between the inner and outer tank shells would equalize, therefore containing the fluids until repairs are completed.

ADEC has carefully considered your request and evaluated the available information. **Based upon the information provided, ADEC is granting waivers of the secondary containment requirements of 18 AAC 75.075(a) for the 3 tanks in question.** The waivers are subject to the following condition:

> Controls which monitor the interstitial space between the inner and outer walls of the tank are to be tested monthly and the results recorded. The records will be made available to ADEC upon request.

This condition is based on API 653 4.3.1.1 routine in-service inspection, and 18 AAC 75.065(h)(4)(A) leak detection system. BPXA is required to have a leak detection system and to perform monthly in-service inspections.

This waiver does not relieve the planholder of the responsibility for securing other federal, state or local approvals or permits, and that the planholder is still required to comply with all other applicable laws.

If you have any questions, please contact Lydia Miner at (907) 269-7536 or me at (907) 465-5290.

Sincerely,

Jeff Mach

Jeff Mach
Oil and Gas Coordinator

cc: Lydia Miner, ADEC
Carl Lautenberger, EPA
Jeff Walker, MMS
Capt. William Hutmacher, USCG
Steve Schmitz, ADNR
Al Ott, ADF&G, Fairbanks
Gordon Brower, North Slope Borough
Leon Lynch, DNR/DMLW
Kellie Westphall, DNR/DMLW
Glenn Gray, DGC

PART 3. SUPPLEMENTAL INFORMATION [18 AAC 75.425(e)(3)]

3.1 FACILITY DESCRIPTION AND OPERATIONAL OVERVIEW [18 AAC 75.425(e)(3)(A)]

This section describes many facilities and operations, some of which are not regulated by the Alaska Department of Environmental Conservation (ADEC).

3.1.1 FACILITY OWNERSHIP AND GENERAL SITE DESCRIPTION

Following is the ownership breakdown for Northstar:

- BP Exploration (Alaska) Inc. (BPXA), 98.08 percent, and
- Murphy Oil, 1.92 percent.

Northstar is a self-contained offshore production facility on a gravel island outside the barrier islands in the Alaskan Beaufort Sea, with pipelines to shore. Water depth at the island is approximately 39 feet. The Northstar facility lies about 6 miles offshore of the Point McIntyre/Point Storkersen area. The Northstar development is built on Seal Island, an exploration island constructed by Shell Oil Company and Amerada Hess in 1983. The current facility was constructed in 1999-2000, and production started in 2001.

The island lies in State waters of the Beaufort Sea. The location of Northstar and its facilities are shown in Figures B-1 through B-4 in Appendix B. The drilling and production systems, base operations center, and support facilities are built on the island. Critical infrastructure supporting operation and maintenance of the production facility is as follows:

- Permanent camp and medical care facility;
- Utilities, including potable water generation, waste water treatment, solids incineration, communications system, and firewater systems;
- Diesel fuel and water storage tanks;
- Warehouse/shop;
- Helideck and dockface; and
- Class 1 disposal well.

Major facilities are elevated on spread footings. The footings prevent heat input to the gravel fill, reduce snow accumulation around the buildings, and allow visual inspection under buildings.

Northstar does not have permanent gravel roads connecting it to existing North Slope facilities.

3.1.2 FACILITY OIL STORAGE CONTAINERS [18 AAC 75.425(e)(3)(A)(i) AND (ii)]

Table 3-1 describes the type, capacity, installation date, design, construction, stored product, inspection date, and other information for each ADEC-regulated stationary oil storage tank. Appendix A contains similar information for regulated portable shop-built oil storage tanks. Figure B-3 in Appendix B shows the location of the oil storage tanks.

TABLE 3-1: REGULATED STATIONARY OIL STORAGE TANK DATA (TANKS GREATER THAN 10,000 GALLONS)

TANK NO. SKID	PRODUCT TYPE DESCRIPTION NOMINAL DESIGN CAPACITY (GALLONS)	FABRICATION/ INSTALLATION DATE CONSTRUCTION STANDARD	INFLOW CONTROL VALVE	OVERFILL PROTECTION DEVICE (OFPD)	OFPD TESTING	LEAK DETECTION SYSTEMS AND PROCEDURES DESCRIPTION	CIC TANK INTEGRITY INSPECTION (API 653) LAST / NEXT INSPECTION	TANK SECONDARY CONTAINMENT DESCRIPTION CAPACITY (GALLONS)	TANK TRUCK LOADING/PERMANENT UNLOADING AREA SECONDARY CONTAINMENT DESCRIPTION
T-S3-8202 305	(b) (7)(F), (b) (3) [redacted]	2000 American Petroleum Institute (API) Standard 650	(b) (3), (b) (7)(F) [redacted]	[redacted]	Monthly or before each transfer, whichever is less frequent	In the event of a leak in the inner tank wall, diesel will flow through a 1-inch ball valve and sight flow glass, and into a 6-inch pipe. Alarm will sound in control room.	Internal: 2009 / 2019 External: 2009 / 2014	(b) (7)(F), (b) (3) [redacted]	[redacted]
T-3020 Pump House	[redacted]	2001 API 650	[redacted]	[redacted]	Monthly or before each transfer, whichever is less frequent	A float-operated, external cage switch detects leaks between the tank's inner and outer walls.	Internal: 2009 / 2019 External: 2009 / 2014	[redacted]	[redacted]
T-6140 Pump House	[redacted]	2001 API 650	[redacted]	[redacted]	Monthly or before each transfer, whichever is less frequent	A float-operated, external cage switch detects leaks between the tank's inner and outer walls.	Internal: 2009 / 2019 External: 2009 / 2014	[redacted]	[redacted]

*Double-walled tanks are waivered (see January 8, 2002 waiver in Part 2).

3.1.3 TRANSFER PROCEDURES [18 AAC 75.425(e)(3)(A)(vi)]

General North Slope fuel transfer procedures are discussed in Section 2.1.5. Northstar-specific guidelines are presented in the U.S. Coast Guard (USCG) Fuel Transfer Operations Manual.

3.1.4 GENERAL DESCRIPTION OF OIL PIPELINES AND PROCESSING FACILITIES [18 AAC 75.425(e)(3)(A)(vii)]

PROCESSING FACILITIES

The production facility is capable of handling 85,000 barrels of oil per day (bopd), 30 million barrels per day of produced water, and 600 million standard cubic feet per day of total injected gas. The processing facilities consist of three primary modules. The first module contains the separation, gas dehydration, and power generation equipment. The second module contains the low- and high-pressure gas compression equipment. The third module contains the water storage and disposal systems.

The facility is designed as a single production separation train with two high-pressure gas compression trains and no dedicated backup of process equipment. The main process module houses production separators, gas coolers and dehydration facilities, a natural gas liquids (NGLs) stabilization system, turbine-driven generators, a waste heat recovery system for process and utility heat, gas relief collection headers/scrubbers, fuel gas letdown skid, and plant air and nitrogen systems.

Process facility components are as follows:

- A mixture of oil, water, and gas is received from the producing wells in the high-pressure separator and is separated by phase. Light hydrocarbon components including methane, ethane, and propane are removed from the oil; and heavier NGLs, including butane and pentane, are mixed with the crude. NGL recovery adds about 4 percent to the volume of sales oil. Sales-quality oil is cooled using air coolers before it enters the main oil pipeline to shore. Northstar utilizes air cooling only to reduce the sales crude temperature from 153 degrees Fahrenheit (°F) to 50°F (annual average) for export from the island. At Pump Station 1, sales crude is re-heated to 105°F (minimum) prior to delivery in order to meet Trans Alaska Pipeline System specifications.
- Recovered vapor is combined with the overhead gas from the high-pressure separator. Overhead gas and recovered vapors from the high-pressure separator are combined and cooled to 80°F using air coolers. The resulting condensed liquids and gases are separated in a filter separator, with the gas being routed to a triethylene glycol contractor where water is removed.
- Produced gas contains significant amounts of NGLs (primarily butanes and pentanes), which are condensed and recovered using air cooling. The recovered NGLs are stabilized and sent to the crude stabilizer for final blending with sales oil.
- After NGLs are recovered, the residue gas is compressed for re-injection into the Northstar reservoir. This is accomplished with two gas-turbine-driven compressors (approximately 32,000 horsepower each). Gas imported from shore via the gas pipeline arrives at the island at high pressure. This import gas stream is high-quality natural gas that has already been dehydrated with NGLs, removed, and compressed onshore prior to transport to the island. Once on the

island, it combines with Northstar gas at 685 pounds per square inch gauge (psig) and is compressed to 5,500 psig for injection.

- Utilities supplied at the facility include instrument air, service air, nitrogen, high-pressure and low-pressure fuel-gas systems, diesel fuel storage, and heating medium.
- A flare provides the safe and controlled release of safety emergency vents, relief-valve discharges during process upsets, maintenance blowdowns, and other releases relating to the safety of the facility and operating personnel.

WELLS AND WELL PADS

Northstar currently has 21 production wells, six gas injection wells, and two Class I waste disposal wells. The piperack along the well row has headers for well testing, single-train production, gas injection, and water disposal. Hydraulic well system and individual well safety panels are included in the piperack, as are utility water, fuel gas, highline electric connections, and vacuum/fluid exchange headers to support drill rig operations.

PIPELINES

The pipeline system originates on Seal Island and consists of offshore buried pipelines and onshore aboveground segments. The pipeline system, installed in 2000, includes one 10-inch common carrier crude oil transmission pipeline to transport sales oil to the Trans Alaska Pipeline System and a gas line. The two pipelines are buried in a common offshore trench from Seal Island to an onshore crossing located west of the DEW Line Site near Pt. Storkersen. The onshore pipeline segments are aboveground except at road crossings at E Pad Road and C Pad Road in the Greater Prudhoe Bay Unit, and at several caribou crossings. Figures B-1 and B-2 in Appendix B show the locations of the pipeline segments.

(b) (3), (b) (7)(F) [redacted]

INSTRUMENTATION AND CONTROLS

(b) (3), (b) (7)(F) [redacted]

[redacted]

(b) (3), (b) (7)(F)

CRUDE OIL AND RESERVOIR CHARACTERISTICS

The Northstar reservoir formation is the Prudhoe Bay member of the Ivishak Formation of the Sadlerochit Group. Northstar crude is very light (42 API gravity), with a low viscosity (0.14 centipoise) and excellent mobility ratio. Initial gas-to-oil ratios were approximately 2,200 standard cubic feet, with a carbon dioxide content of 5 percent. The oil is volatile, and with a reservoir pressure of 5,300 psig, it is very close to its bubble point of 5,000 pounds per square inch absolute. The reservoir is at high pressure and the primary drive mechanism is thought to be pressure depletion. Gas re-injection is used from startup to maintain reservoir pressure and improve recovery.

PHMSA 000109578

TABLE 3-2: PIPELINE DESCRIPTION

ITEM	CRUDE OIL TRANSMISSION PIPELINE
Transported substance	Processed oil to TAPS specifications
Substance specific gravity (@ standard temperature/pressure)	0.79 (water = 1.0)
Maximum allowable operating pressure	1480 psig
Normal operating pressure	850 psig
Pipeline outside diameter	10.750 inches
Pipeline wall thickness	
Offshore	
Mainline	0.594 inch
Riser	0.595 inch
Overland	
Mainline	0.279 inch
Station	0.307 inch
Pipe material grade	
Offshore	API 5L Grade X52
Overland	API 5L Grade X65
Design hoop stress factor	
Mainline	0.72
Riser/Station	0.60
Offshore limit strain	
Normal operating condition	1.2%
Design contingency	1.8%
External coating	
Offshore	Fusion Bonded Epoxy (FBE)
Overland	Polyurethane foam insulation/galvanized jacket
Pipeline specific gravity (empty)	
Offshore	1.60
Overland	Not applicable
Cathodic protection	
Offshore	Sacrificial anodes
Overland	None
Test pressure/duration	[redacted]
Mainline	
Island riser	
Inspection piggable	[redacted]
Valves	[redacted]
Pump/compressor station location	[redacted]
Heating/refrigeration stations	[redacted]
Design life	
Pipeline temperature	Annual average (inlet): 50°F Summer average (inlet): 70°F Maximum daily average (inlet): 85°F Maximum temperature (inlet): 100°F
Pipeline support/burial	
Offshore[1]	
Outside barrier islands	Buried, 7 feet depth of cover
Within 3,000 feet of Seal Island	Buried, 9 feet depth of cover
Lagoon	Buried, 6 feet depth of cover
Overland	VSM supported
Design code/regulation	American Society of Mechanical Engineers B31.4/49 CFR Part 195

[1] Locally greater depth of cover (distance from original seabed to top of pipe) is provided in areas such as the Seal Island and Pt. Storkersen approaches. The trench is backfilled with a minimum 6 feet of soil over the pipelines.

PART 4. BEST AVAILABLE TECHNOLOGY [18 AAC 75.425(e)(4)]

See Volume 1 for the following sections:

4.1 Communications [18 AAC 75.425(e)(4)(A)(i)]

4.2 Source Control [18 AAC 75.425(e)(4)(A)(i)]

4.3 Trajectory Analyses and Forecasts [18 AAC 75.425(e)(4)(A)(i)]

4.4 Wildlife Capture, Treatment, and Release Programs [18 AAC 75.425(e)(4)(A)(i)]

4.5 CATHODIC PROTECTION FOR FIELD-CONSTRUCTED OIL STORAGE TANKS [18 AAC 75.425(e)(4)(A)(ii)]

Northstar oil storage tanks are elevated and therefore not subject to the cathodic protection requirements of 18 AAC 75.065(i)(3).

4.6 LEAK DETECTION SYSTEM FOR FIELD-CONSTRUCTED OIL STORAGE TANKS [18 AAC 75.425(e)(4)(A)(ii)]

ADEC-regulated oil storage tanks are elevated above the pad and as such are accessible to direct observation of leaks. The tanks are further equipped with leak detection systems consisting of level-sensing instrumentation monitoring the interstitial space of double-walled tanks. See Table 4-4 for the best available technology (BAT) analysis of leak detection systems. The alarms for this instrumentation are monitored in the control room.

TABLE 4-4: BEST AVAILABLE TECHNOLOGY ANALYSIS LEAK DETECTION SYSTEM FOR FIELD-CONSTRUCTED OIL STORAGE TANKS

BAT EVALUATION CRITERIA	EXISTING METHOD: FLOAT-OPERATED EXTERNAL CAGE LEVEL SWITCH (DIESEL TANK ONLY)	EXISTING METHOD: ANNULAR SPACE DETECTION (WATER SURGE AND WELL CLEANUP TANKS)	ALTERNATE METHOD: EXTERNAL SUMP C/W LEVEL SWITCH
AVAILABILITY: Whether technology is best in use in other similar situations or is available for use by applicant	Method is available and used by tank manufacturers.	Method is available and used by tank manufacturers.	A collection basin or sump is standard practice for containment of spills in the oil and most other industries.
TRANSFERABILITY: Whether each technology is transferable to applicant's operations	Method is transferable.	Method is transferable.	Method is transferable.
EFFECTIVENESS: Whether there is a reasonable expectation each technology will provide increased spill prevention or other environmental benefits	This method provides a means of rapidly identifying any leak and annunciating an alarm to operations.	This method provides a means of rapidly identifying any leak and annunciating an alarm to operations.	This method provides a means of rapidly identifying any leak and annunciating the leak to Operations.
COST: The cost to the applicant of achieving BAT, including consideration of that cost relative to the remaining years of service of the technology in use by the applicant	Cost is minimal.	Cost is minimal.	Cost is minimal.
AGE AND CONDITION: The age and condition of the technology in use by the applicant	Method is proven technology.	Method is proven technology used by double-walled tank manufacturers.	Method is proven technology that has been utilized for many years.
COMPATIBILITY: Whether each technology is compatible with existing operations and technology in use by the applicant	Method is compat ble.	Method is compatible.	Method is compat ble.
FEASIBILITY: The practical feasibility of each technology in terms of engineering and other operational aspects	Detects a leak based on a rising level.	Detects a leak based on a rising level.	Detects a leak based on a rising level.
ENVIRONMENTAL IMPACTS: Whether other environmental impacts of each technology, such as air, land, water pollution and energy requirements, offset any anticipated environmental benefits	Standard practice.	Simple, no moving parts.	Standard practice, simple, few moving parts.

4.7 LIQUID LEVEL DETERMINATION FOR OIL STORAGE TANKS [18 AAC 75.425(e)(4)(A)(ii)]

The BAT for liquid level determination in stationary bulk oil storage tanks is provided in Table 4-5. (b) (3), (b) [redacted]

(b) (3), (b) (7)(F) [redacted]

TABLE 4-5: BEST AVAILABLE TECHNOLOGY ANALYSIS
STATIONARY STORAGE TANK LIQUID LEVEL DETERMINATION

(b) (3), (b) (7)(F)

BAT EVALUATION CRITERIA	
AVAILABILITY: Whether technology is best in use in other similar situations or is available for use by applicant	[redacted]
TRANSFERABILITY: Whether each technology is transferable to applicant's operations	

PHMSA 000109584

TABLE 4-5 (CONTINUED): BEST AVAILABLE TECHNOLOGY ANALYSIS
STATIONARY STORAGE TANK LIQUID LEVEL DETERMINATION

(b) (3), (b) (7)(F)

BAT EVALUATION CRITERIA	[redacted]
EFFECTIVENESS: Whether there is a reasonable expectation each technology will provide increased spill prevention or other environmental benefits	
COST: The cost to the applicant of achieving BAT, including consideration of that cost relative to the remaining years of service of the technology in use by the applicant	
AGE AND CONDITION: The age and condition of the technology in use by the applicant	
COMPATIBILITY: Whether each technology is compatible with existing operations and technology in use by the applicant	

TABLE 4-5 (CONTINUED): BEST AVAILABLE TECHNOLOGY ANALYSIS
STATIONARY STORAGE TANK LIQUID LEVEL DETERMINATION

(b) (3), (b) (7)(F)

BAT EVALUATION CRITERIA	[redacted]		
FEASIBILITY: The practical feasibility of each technology in terms of engineering and other operational aspects			
ENVIRONMENTAL IMPACTS: Whether other environmental impacts of each technology, such as air, land, water pollution and energy requirements, offset any anticipated environmental benefits			

Table 4-6 presents the BAT analysis for liquid level determination for portable storage tanks 10,000 gallons and larger. Electronic types typically employ ultrasonic or microwave frequency transducers. In the context of portable and temporary tanks the effective utility of the devices is greatly compromised.

Portable, temporary tanks located on gravel pads, or on rigs, are subject to vibrations and jolts. Experience shows that use of the devices on portable and temporary tanks results in liquid level measurement errors and frequent false alarms in high level and leak detection contexts. Handling during loading, transportation, and unloading may result in physical damage to the level determination device or electronic components contained therein (as applicable). Float type devices are particularly prone to "jamming" under these conditions. While it is possible to tune associated controller outputs to mitigate the effects of vibration and jolts, such a state of tune would significantly decrease their accuracy and response times in terms of liquid level measurement and preclude their use as leak detection devices.

In addition, should these devices be used to control automatic shutoff valves or pump shutoff relays, unanticipated valve closures or pump shutdowns may occur, with potential oil spill consequences. The inability of these devices to function accurately and reliably on portable and temporary tanks, and the significant cost of custom construction, installation, and maintenance, preclude their use.

The multiphase nature of fluids adversely impacts the accuracy and reliability displayed by a variety of level determination devices. Flow test tank fluids are typically composed of oil, water, associated emulsions, and suspended solids. Microwave frequency device accuracy is compromised by variations in liquid dielectric constant and electrical conductivity; accordingly, application in multiphase liquid contexts is contraindicated. Alternatively, ultrasonic devices require contact with the process fluid; solids buildup or emulsion adherence to the sensor will result in decreased accuracy and the need for frequent maintenance.

Float type devices are also subject to greatly reduced accuracy and reliability, resulting from solids content. These solids facilitate float "sticking" and "jamming." In addition, extreme cold weather results in pulleys that may not roll freely or freeze up altogether, or associated cable systems that become inflexible. Any one or more of these effects will render the device unreliable in terms of accurate level determination

[redacted]

(b) (3), (b) (7)(F)

In addition to manual gauging and direct observation, the application of additional liquid level determination devices to portable and temporary tanks in remote Arctic environments is not desirable for the following reasons:

- Significant physical damage, or damage to associated electronic components, as a result of loading, unloading, or transportation;
- Requirement for power source – a potential source of ignition;
- Need for frequent maintenance;

bp

- Lack of warranty;
- Decreased accuracy;
- Decreased reliability; and
- Significant cost (e.g., device, power, installation, maintenance and replacement).

Two persons are involved in visual inspection of the liquid level in an ADEC-regulated portable tank not equipped with a fixed level determination device while the tank is receiving oily liquids. One person operates the pump. The other person visually monitors the liquid level to prevent overfilling. The method is the best means of immediately determining the liquid level of ADEC-regulated portable bulk storage tanks, as specified in 18 AAC 75.066(g)(1)(C) and (D).

TABLE 4-6: BEST AVAILABLE TECHNOLOGY ANALYSIS
PORTABLE OIL STORAGE TANK LIQUID LEVEL DETERMINATION SYSTEM

BAT EVALUATION CRITERIA	**EXISTING METHOD: VISUAL INSPECTION**	(b) (3), (b) (7)(F) [redacted]
AVAILABILITY: Whether technology is best in use in other similar situations or is available for use by applicant	Existing method	[redacted]
TRANSFERABILITY: Whether each technology is transferable to applicant's operations	Transferable	[redacted]
EFFECTIVENESS: Whether there is a reasonable expectation each technology will provide increased spill prevention or other environmental benefits	Highly effective with strict adherence to Best Management Practices and local procedure. Tank liquid levels are determined from direct observation through the hatch using a flashlight, fuel strapping tape, etc.	[redacted]
COST: The cost to the applicant of achieving BAT, including consideration of that cost relative to the remaining years of service of the technology in use by the applicant.	Not applicable	[redacted]
AGE AND CONDITION: The age and condition of technology in use by the applicant	Procedures have been in place since 1993 for fuel transfer operations.	[redacted]
COMPATIBILITY: Whether each technology is compatible with existing operations and technologies in use by the applicant	Compatible and widely used. Requires no change.	[redacted]

TABLE 4-6 (CONTINUED): BEST AVAILABLE TECHNOLOGY ANALYSIS
PORTABLE OIL STORAGE TANK LIQUID LEVEL DETERMINATION SYSTEM

BAT EVALUATION CRITERIA	EXISTING METHOD: VISUAL INSPECTION	[redacted]
FEASIBILITY: The practical feasibility of each technology in terms of engineering and other operational aspects	Feasible and preferred due to potential for electronic or pneumatic systems to experience damage from rough handling.	
ENVIRONMENTAL IMPACTS: Whether other environmental impacts of each technology, such as air, land, water pollution, and energy requirements offset any anticipated environmental benefits	None	

(b) (3), (b) (7)(F)

4.8 MAINTENANCE PRACTICES FOR BURIED FACILITY OIL PIPING [18 AAC 75.425(e)(4)(A)(ii)]

Buried facility piping in direct contact with soil is not present at Northstar. The requirement of 18 AAC 75.080(b) does not apply.

4.9 PROTECTIVE COATINGS AND CATHODIC PROTECTION FOR FACILITY OIL PIPING [18 AAC 75.425(e)(4)(A)(ii)]

4.9.1 PROTECTIVE COATINGS FOR BURIED, SUBMERGED, AND ABOVEGROUND FACILITY OIL PIPING

No facility piping subject to buried or submerged corrosion service is present at Northstar. The requirements of 18 AAC 75.080(d), 18 AAC 75.080(k)(1), and 18 AAC 75.080(l) do not apply.

For aboveground facility oil piping, shop-applied insulated systems with an outer sheet metal jacket are considered to meet protective coating requirements of 18 AAC 75.080)(l), except where inspection finds a breach in the outer barrier. Where a breach is found, inspections are conducted by non-destructive means to determine if corrosion is present. Where corrosion is found, insulation is stripped, and the pipe is inspected to determine fitness for service. The location then receives a protective barrier coating directly on the pipeline in accordance with re-insulation and coating specifications. New insulated pipelines utilize shop-applied fusion-bonded epoxy (FBE) coatings directly on the pipe or are made of corrosion-resistant alloys. Field coatings at weld joints or long pipe sections may include field-applied FBE, high-performance liquid coating, or high-performance tape coatings placed directly on the pipe. This also applies to facility piping in culverts or utiliways installed after December 30, 2006, which are inaccessible for visual inspection.

4.9.2 CATHODIC PROTECTION SYSTEMS FOR BURIED FACILITY PIPING

The requirements of 18 AAC 75.080(d) and 18 AAC 75.080(k)(1) do not apply. Buried facility piping is not present at Northstar.

4.10 MAINTENANCE PRACTICES FOR BURIED FACILITY OIL PIPING – CORROSION SURVEYS [18 AAC 75.425(e)(4)(A)(ii)]

Northstar does not have facility oil piping buried directly in soil. The requirement in 18 AAC 75.080(k)(2) does not apply.

4.11 LEAK DETECTION FOR CRUDE OIL TRANSMISSION PIPELINES [18 AAC 75.425(e)(4)(A)(iv)]

As required by 18 AAC 75.425(e)(4)(A)(iv), a BAT analysis was conducted for leak detection technologies applicable to the Northstar pipeline. These technologies are as follows:

(b) (3), (b) (7)(F)

[redacted]

The rationale in determining the most appropriate leak detection system for North Slope transmission lines is based on operation philosophy, in addition to criteria stipulated in the BAT analysis. First, there must be redundancy (i.e., reliance will not be placed on a single leak detection system). The technology must be state-of-the-art and capable of immediate detection of a sudden large-volume loss of product, as well as detection of a low-threshold chronic (pinhole) leak. The system must also be commercially available, in use on similar pipeline systems, be composed of two leak detection systems that are readily integrated with each other, and must be available from a vendor with a proven track record.

To obtain the U.S. Army Corps of Engineers (USACE) Permit, the Northstar Project was required to meet the threshold leak volume stipulated by the USACE (Stipulation 18) of 32.5 barrels per day. The stipulation applied to the subsea portion of the pipeline. After researching the best available technologies, the LEOS leak detection and location system was selected for this purpose. Field tests demonstrated the ability of LEOS to detect and locate a very small hydrocarbon leak. The specification for the Northstar subsea pipeline was to detect a leak of approximately 1 barrel in a 24-hour period, and to locate it within 50 meters (approximately 5 percent of the 10 kilometer length).

In investigating the various leak detection systems available and determining the best application for the Northstar pipeline, it became apparent that each leak detection system has its associated strengths and weaknesses that depend on the specific pipeline operating characteristics. The type of system selected depends on the combination of several technologies including flow measurement, instrumentation, communications, computer hardware and software, and ultimately experience in operating a system under similar circumstances (i.e., similar pipeline flow conditions). In consideration of the environmental conditions at Northstar and the flow conditions in the pipeline; it was essential the selected system have an established and verifiable track record in the North Slope crude oil pipelines. In addition, the chosen system must be redundant (i.e., reliance is not placed on a single leak detection system), the technology must be state-of-the-art and capable of immediately detecting a sudden large-volume loss, and it should be capable of detecting a low-threshold chronic leak.

(b) (3), (b) (7)(F)

[redacted]

(b) (3), (b) (7)(F)

[redacted]

(b) (3), (b) (7)(F)

[redacted]

(b) (3), (b) (7)(F)

[redacted]

TABLE 4-7 (CONTINUED): BEST AVAILABLE TECHNOLOGY ANALYSIS
LEAK DETECTION FOR CRUDE OIL TRANSMISSION PIPELINE

(b) (3), (b) (7)(F)

BAT EVALUATION CRITERIA	[redacted]	ALTERNATE SYSTEM: VISUAL IDENTIFICATION
TRANSFERABILITY: Whether each technology is transferable to applicant's operations	[redacted]	Can be used for aboveground segment of crude oil transmission pipeline.
EFFECTIVENESS: Whether there is a reasonable expectation each technology will provide increased spill prevention or other environmental benefits	[redacted]	Visual identification is an effective means to identify a leak that can be visually detected. Sometimes leaks occur that are below the threshold limit of the leak detection system and are spotted by visual detection. Visual identification must be utilized in conjunction with an automated leak detection system.

TABLE 4-7 (CONTINUED): BEST AVAILABLE TECHNOLOGY ANALYSIS LEAK DETECTION FOR CRUDE OIL TRANSMISSION PIPELINE

BAT EVALUATION CRITERIA	(b) (3), (b) (7)(F) [redacted]	ALTERNATE SYSTEM: VISUAL IDENTIFICATION
COST: The cost to the applicant of achieving BAT, including consideration of that cost relative to the remaining years of service of the technology is use by the applicant.	[redacted]	The cost would be based on trips to cover the pipeline right-of-way. No upfront investment.
AGE AND CONDITION: The age and condition of technology in use by the applicant	[redacted]	Method is current.
COMPATIBILITY: Whether each technology is compatible with existing operations and technologies in use by the applicant	[redacted]	Compatible, but small leaks in the below-grade sections might go undetected.
FEASIBILITY: The practical feasibility of each technology in terms of engineering and other operational aspects	[redacted]	Visual identification is not a feasible method to continuously monitor the entire pipeline. It is useful as a supplement to an online leak detection system.

TABLE 4-7 (CONTINUED): BEST AVAILABLE TECHNOLOGY ANALYSIS
LEAK DETECTION FOR CRUDE OIL TRANSMISSION PIPELINE

BAT EVALUATION CRITERIA	[redacted]	ALTERNATE SYSTEM: VISUAL IDENTIFICATION
ENVIRONMENTAL IMPACTS: Whether other environmental impacts of each technology, such as air, land, water pollution, and energy requirements, offset any anticipated environmental benefits		No environmental impacts.

PHMSA 000109600

PART 5. RESPONSE PLANNING STANDARD [18 AAC 75.425(e)(5)]

Part 5, Response Planning Standard, is in Volume 1.

APPENDIX A

ADEC-REGULATED SHOP-FABRICATED STORAGE TANKS TABLE

APPENDIX A: ADEC-REGULATED PORTABLE, SHOP-FABRICATED STORAGE TANK DATA
TANKS GREATER THAN 10,000 GALLONS ON BPXA LEASES

Tank Number	Tank Owner	Typical Location	Description	Fabrication Date	Nominal Design Capacity (gallons)	Product Type	Secondary Containment Description	Internal Inspection Last; Next	External Inspection Last; Next	Inflow Control Valve	Liquid Level Mechanism/Overfill Protection	Leak Detection Systems and/or Procedures	Corrosion Protection
108	TANK-O	Varies	Double-walled	1983	(b) (7)(F), (b) (3) [redacted]	Miscellaneous hydrocarbons and water	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2010; 2015	2010; 2015	(b) (3), (b) (7)(F) [redacted]	[redacted]	[redacted]	Internal Lining
111	TANK-O	Varies	Rectangular on Skid	1983	[redacted]	Miscellaneous hydrocarbons and water	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2010; 2015	2010; 2015	[redacted]	[redacted]	[redacted]	None
114	TANK-O	Varies	Horizontal, rectangular double wall	1983	[redacted]	Hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	[redacted]	[redacted]	[redacted]	Internal Lining
115	TANK-O	Varies	Horizontal, double wall	1983	[redacted]	Miscellaneous hydrocarbons and water	Double wall[1]	2010; 2015	2010; 2015	[redacted]	[redacted]	[redacted]	Internal Lining
116	TANK-O	Varies	Horizontal, double wall	1983	[redacted]	Hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	[redacted]	[redacted]	[redacted]	Internal Lining
117	TANK-O	Varies	Horizontal, double wall	1983	[redacted]	Hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	[redacted]	[redacted]	[redacted]	Internal Lining
118	TANK-O	Varies	Horizontal, double wall	1983	[redacted]	Hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	[redacted]	[redacted]	[redacted]	Internal Lining
119	TANK-O	Varies	Horizontal, double wall	1983	[redacted]	Hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	[redacted]	[redacted]	[redacted]	Internal Lining
121	TANK-O	Varies	Horizontal, rectangular double wall	1983	[redacted]	Hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	[redacted]	[redacted]	[redacted]	Internal Lining
122	TANK-O	Varies	Horizontal, rectangular double wall	1983	[redacted]	Hydrocarbons	Double wall[1]	2009; 2014	2009; 2014	[redacted]	[redacted]	[redacted]	Internal Lining
123	TANK-O	Varies	Horizontal, rectangular double wall	1983	[redacted]	Hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	[redacted]	[redacted]	[redacted]	Internal Lining
124	TANK-O	Varies	Horizontal, rectangular double wall	1983	[redacted]	Hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	[redacted]	[redacted]	[redacted]	Internal Lining
125	TANK-O	Varies	Rectangular on Skid	1983	[redacted]	Miscellaneous Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2010; 2015	2010; 2015	[redacted]	[redacted]	[redacted]	None
127	TANK-O	Varies	Horizontal, rectangular double wall	1983	[redacted]	Hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	[redacted]	[redacted]	[redacted]	Internal Lining
128	TANK-O	Varies	Horizontal, rectangular double wall	1983	[redacted]	Hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	[redacted]	[redacted]	[redacted]	None
130	TANK-O	Varies	Double-wall, welded steel; Herc	1983	[redacted]	Miscellaneous hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	[redacted]	[redacted]	[redacted]	Internal Lining

APPENDIX A: ADEC-REGULATED PORTABLE, SHOP-FABRICATED STORAGE TANK DATA
TANKS GREATER THAN 10,000 GALLONS ON BPXA LEASES

Tank Number	Tank Owner	Typical Location	Description	Fabrication Date	Nominal Design Capacity (gallons)	Product Type	Secondary Containment Description	Internal Inspection Last; Next	External Inspection Last; Next	Inflow Control Valve	Liquid Level Mechanism/Overfill Protection	Leak Detection Systems and/or Procedures	Corrosion Protection
131	TANK-O	Varies	Horizontal, double wall	1983	(b) (7)(F), (b) (3) [redacted]	Hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	(b) (3), (b) (7)(F) [redacted]	[redacted]	[redacted]	None
132	TANK-O	GPB	Horizontal, rectangular double wall	1983	[redacted]	Hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	[redacted]	[redacted]	[redacted]	None
73020	BPXA GWO	GPB	Tiger Tank	2000	[redacted]	Miscellaneous Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2011; 2016	2011; 2016	[redacted]	[redacted]	[redacted]	None
73021	BPXA GWO	GPB	Tiger Tank	2000	[redacted]	Miscellaneous Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2011; 2016	2011; 2016	[redacted]	[redacted]	[redacted]	None
73022	BPXA GWO	GPB	Tiger Tank	2000	[redacted]	Miscellaneous Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2010; 2015	2010; 2015	[redacted]	[redacted]	[redacted]	None
73023	BPXA GWO	GPB	Tiger Tank	2000	[redacted]	Miscellaneous Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2011; 2016	2011; 2016	[redacted]	[redacted]	[redacted]	None
73024	BPXA GWO	GPB	Tiger Tank	2000	[redacted]	Miscellaneous Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2010; 2015	2010; 2015	[redacted]	[redacted]	[redacted]	None
73043	BPXA GWO	GPB	Open top	1988	[redacted]	Miscellaneous Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2012; 2017	2012; 2017	[redacted]	[redacted]	[redacted]	None
73047	BPXA GWO	GPB	Open top	1984	[redacted]	Miscellaneous Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2011; 2016	2011; 2016	[redacted]	[redacted]	[redacted]	None
73052	BPXA GWO	GPB	Tiger Tank	1995	[redacted]	Miscellaneous Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2012; 2015	2012; 2015	[redacted]	[redacted]	[redacted]	Internal Paint Coating
73067	BPXA GWO	GPB	Open top	2002	[redacted]	Miscellaneous Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2011; 2016	2011; 2016	[redacted]	[redacted]	[redacted]	None

APPENDIX A: ADEC-REGULATED PORTABLE, SHOP-FABRICATED STORAGE TANK DATA TANKS GREATER THAN 10,000 GALLONS ON BPXA LEASES

Tank Number	Tank Owner	Typical Location	Description	Fabrication Date	Nominal Design Capacity (gallons)	Product Type	Secondary Containment Description	Internal Inspection Last; Next	External Inspection Last; Next	Inflow Control Valve	Liquid Level Mechanism/Overfill Protection	Leak Detection Systems and/or Procedures	Corrosion Protection
73068	BPXA GWO	GPB	Open top	2002	(b) (7)(F), (b) (3) [redacted]	Miscellaneous Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2011; 2016	2011; 2016	(b) (3), (b) (7)(F) [redacted]	[redacted]	[redacted]	None
73069	BPXA GWO	GPB	Open top	2002	[redacted]	Miscellaneous Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2011; 2016	2011; 2016	[redacted]	[redacted]	[redacted]	None
73070	BPXA GWO	GPB	Open top	2002	[redacted]	Miscellaneous Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2010; 2015	2010; 2015	[redacted]	[redacted]	[redacted]	None
73080	BPXA GWO	GPB	Double-wall flowback Tank	2004	[redacted]	Miscellaneous Hydrocarbons	Double wall[1]	2013; 2017	2013; 2017	[redacted]	[redacted]	[redacted]	None
73081	BPXA GWO	GPB	Double-wall flowback Tank	2004	[redacted]	Miscellaneous Hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	[redacted]	[redacted]	[redacted]	None
73091	BPXA GWO	GPB / DSM	Horizontal, rectangular double wall	2006	[redacted]	Hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	[redacted]	[redacted]	[redacted]	Internal Lining
73092	BPXA GWO	GPB / DSM	Horizontal, rectangular double wall	2006	[redacted]	Hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	[redacted]	[redacted]	[redacted]	Internal Lining
73093	BPXA GWO	GPB / DSM	Horizontal, rectangular double wall	2006	[redacted]	Hydrocarbons	Double wall[1]	2012; 2017	2012; 2017	[redacted]	[redacted]	[redacted]	Internal Lining
73094	BPXA GWO	GPB / DSM	Horizontal, rectangular double wall	2006	[redacted]	Hydrocarbons	Double wall[1]	2012; 2017	2012; 2017	[redacted]	[redacted]	[redacted]	Galvanic Anodes and Internal Lining
73095	BPXA GWO	GPB / DSM	Horizontal, rectangular double wall	2006	[redacted]	Hydrocarbons	Double wall[1]	2012; 2017	2012; 2017	[redacted]	[redacted]	[redacted]	Internal Lining
73096	BPXA GWO	GPB / DSM	Horizontal, rectangular double wall	2006	[redacted]	Hydrocarbons	Double wall[1]	2012; 2017	2012; 2017	[redacted]	[redacted]	[redacted]	Galvanic Anodes and Internal Lining

APPENDIX A: ADEC-REGULATED PORTABLE, SHOP-FABRICATED STORAGE TANK DATA
TANKS GREATER THAN 10,000 GALLONS ON BPXA LEASES

Tank Number	Tank Owner	Typical Location	Description	Fabrication Date	Nominal Design Capacity (gallons)	Product Type	Secondary Containment Description	Internal Inspection Last; Next	External Inspection Last; Next	Inflow Control Valve	Liquid Level Mechanism/Overfill Protection	Leak Detection Systems and/or Procedures	Corrosion Protection
73097	BPXA GWO	GPB / DSM	Horizontal, rectangular double wall	2007	(b) (7)(F), (b) (3) [redacted]	Hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	(b) (3), (b) (7)(F) [redacted]	[redacted]	[redacted]	Internal Lining
73098	BPXA GWO	GPB / DSM	Horizontal, rectangular double wall	2007	[redacted]	Hydrocarbons	Double wall[1]	2012; 2017	2012; 2017	[redacted]	[redacted]	[redacted]	Galvanic Anodes and Internal Lining
73099	BPXA GWO	GPB / DSM	Horizontal, rectangular double wall	2007	[redacted]	Hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	[redacted]	[redacted]	[redacted]	Galvanic Anodes and Internal Lining
73100	BPXA GWO	GPB / DSM	Horizontal, rectangular double wall	2007	[redacted]	Hydrocarbons	Double wall[1]	2012; 2017	2012; 2017	[redacted]	[redacted]	[redacted]	Galvanic Anodes and Internal Lining
73116	BPXA GWO	GPB / DSM	Horizontal, rectangular double wall	2007	[redacted]	Hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	[redacted]	[redacted]	[redacted]	Galvanic Anodes and Internal Lining
73117	BPXA GWO	GPB / DSM	Horizontal, rectangular double wall	2007	[redacted]	Hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	[redacted]	[redacted]	[redacted]	Galvanic Anodes and Internal Lining
55-1901	BPXA	Nordic 1 Rig (GPB)	Double wall, open top	2008	[redacted]	Hydrocarbons	Double wall[1]	2012; 2017	2012; 2017	[redacted]	[redacted]	[redacted]	Internal Lining
94-459	BPXA GWO	GPB	Horizontal, rectangular double wall	2011	[redacted]	Hydrocarbons	Double wall[1]	2011; 2016	2011; 2016	[redacted]	[redacted]	[redacted]	Galvanic Anodes and Internal Lining
94-460	BPXA GWO	GPB	Horizontal, rectangular double wall	2011	[redacted]	Hydrocarbons	Double wall[1]	2011; 2016	2011; 2016	[redacted]	[redacted]	[redacted]	Galvanic Anodes and Internal Lining
94-461	BPXA GWO	GPB	Horizontal, rectangular double wall	2011	[redacted]	Hydrocarbons	Double wall[1]	2011; 2016	2011; 2016	[redacted]	[redacted]	[redacted]	Galvanic Anodes and Internal Lining
94-462	BPXA GWO	GPB	Horizontal, rectangular double wall	2011	[redacted]	Hydrocarbons	Double wall[1]	2011; 2016	2011; 2016	[redacted]	[redacted]	[redacted]	Galvanic Anodes and Internal Lining
95-94-645	BPXA GWO	GPB	Open top	1995	[redacted]	Various	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2010; 2015	2010; 2015	[redacted]	[redacted]	[redacted]	Coal Tar Lining

APPENDIX A: ADEC-REGULATED PORTABLE, SHOP-FABRICATED STORAGE TANK DATA
TANKS GREATER THAN 10,000 GALLONS ON BPXA LEASES

Tank Number	Tank Owner	Typical Location	Description	Fabrication Date	Nominal Design Capacity (gallons)	Product Type	Secondary Containment Description	Internal Inspection Last; Next	External Inspection Last; Next	Inflow Control Valve	Liquid Level Mechanism/Overfill Protection	Leak Detection Systems and/or Procedures	Corrosion Protection
H-01	TANK-O	MPU	Single wall, vertical, upright cylindrical tank	Unknown	(b) (7)(F), (b) (3) [redacted]	Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2011; 2016	2011; 2016	(b) (3), (b) (7)(F) [redacted]	[redacted]	[redacted]	Internal Lining
H-02	TANK-O	MPU	Single wall, vertical, upright cylindrical tank	Unknown	[redacted]	Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2011; 2016	2011; 2016	[redacted]	[redacted]	[redacted]	Internal Lining
H-03	TANK-O	MPU	Single wall, vertical, upright cylindrical tank	Unknown	[redacted]	Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2011; 2016	2011; 2016	[redacted]	[redacted]	[redacted]	Internal Lining
H-04	TANK-O	MPU	Single wall, vertical, upright cylindrical tank	Unknown	[redacted]	Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2011; 2016	2011; 2016	[redacted]	[redacted]	[redacted]	Internal Lining
H-05	TANK-O	MPU	Single wall, vertical, upright cylindrical tank	Unknown	[redacted]	Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2011; 2016	2011; 2016	[redacted]	[redacted]	[redacted]	None
H-06	TANK-O	MPU	Single wall, vertical, upright cylindrical tank	Unknown	[redacted]	Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2011; 2016	2011; 2016	[redacted]	[redacted]	[redacted]	None
H-07	TANK-O	MPU	Single wall, vertical, upright cylindrical tank	Unknown	[redacted]	Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2011; 2016	2011; 2016	[redacted]	[redacted]	[redacted]	Internal Lining
H-08	TANK-O	MPU	Single wall, vertical, upright cylindrical tank	Unknown	[redacted]	Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2011; 2016	2011; 2016	[redacted]	[redacted]	[redacted]	Internal Lining
MPU-05	BPXA GWO	MPU	Upright cylindrical tank, skid mounted	Est. 1983	[redacted]	Miscellaneous Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2012; 2015	2012; 2015	[redacted]	[redacted]	[redacted]	None
MPU-06	BPXA GWO	MPU	Upright cylindrical tank, skid mounted	Est. 1983	[redacted]	Miscellaneous Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2012; 2017	2012; 2017	[redacted]	[redacted]	[redacted]	None

APPENDIX A: ADEC-REGULATED PORTABLE, SHOP-FABRICATED STORAGE TANK DATA
TANKS GREATER THAN 10,000 GALLONS ON BPXA LEASES

Tank Number	Tank Owner	Typical Location	Description	Fabrication Date	Nominal Design Capacity (gallons)	Product Type	Secondary Containment Description	Internal Inspection Last; Next	External Inspection Last; Next	Inflow Control Valve	Liquid Level Mechanism/Overfill Protection	Leak Detection Systems and/or Procedures	Corrosion Protection
MPU-09	BPXA GWO	MPU	Open top, non-insulated	1998	(b) (7)(F), (b) (3) [redacted]	Miscellaneous Hydrocarbons	Welded steel pan in addi ion to berm with impermeable liner	2011; 2016	2011; 2016	(b) (3), (b) (7)(F) [redacted]	[redacted]	[redacted]	None
MPU-10	BPXA GWO	MPU	Open top, non-insulated	1998	[redacted]	Miscellaneous Hydrocarbons	Welded steel pan in addi ion to berm with impermeable liner	2011; 2016	2011; 2016	[redacted]	[redacted]	[redacted]	None
MPU-12	BPXA GWO	MPU	Double-wall Portable Flowback Tank	2000	[redacted]	Miscellaneous Hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	[redacted]	[redacted]	[redacted]	None
MPU-13	BPXA GWO	MPU	Double-wall Portable Flowback Tank	2002	[redacted]	Miscellaneous Hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	[redacted]	[redacted]	[redacted]	None
MPU-14	BPXA GWO	MPU	Double-wall Portable Flowback Tank	2002	[redacted]	Miscellaneous Hydrocarbons	Double wall[1]	2012; 2017	2012; 2017	[redacted]	[redacted]	[redacted]	None
MPU-15	BPXA GWO	MPU	Double wall, rectangular, open top	2007	[redacted]	Hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	[redacted]	[redacted]	[redacted]	Internal Lining
MPU-16	BPXA GWO	MPU	Horizontal, rectangular double wall	2007	[redacted]	Hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	[redacted]	[redacted]	[redacted]	Internal Lining
O-3 (Formerly CTU-03)	TANK-O	GC2 Sand Jetting	Horizontal, double wall	1990	[redacted]	Miscellaneous Hydrocarbons	Double wall[1]	2010; 2015	2011; 2016	[redacted]	[redacted]	[redacted]	Internal Lining
O-5 (Formerly CTU-05)	TANK-O	Varies	Double-walled; open top	1983	[redacted]	Miscellaneous Hydrocarbons	Double wall[1]	2013; 2018	2013; 2018	[redacted]	[redacted]	[redacted]	Internal Lining
O-8 (Formerly CTU-08)	TANK-O	Varies	Tiger Tank	1992	[redacted]	Miscellaneous Hydrocarbons	Double wall[1]	2011; 2016	2011; 2016	[redacted]	[redacted]	[redacted]	Internal Lining
O-9 (Formerly CTU-09)	TANK-O	PS1 (Northstar Pigging)	Horizontal, double wall	1992	[redacted]	Miscellaneous Hydrocarbons	Double wall[1]	2011; 2016	2011; 2016	[redacted]	[redacted]	[redacted]	Internal Lining
O-10	TANK-O	GPB	Open top	1995	[redacted]	Miscellaneous Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2010; 2015	2010; 2015	[redacted]	[redacted]	[redacted]	None

APPENDIX A: ADEC-REGULATED PORTABLE, SHOP-FABRICATED STORAGE TANK DATA
TANKS GREATER THAN 10,000 GALLONS ON BPXA LEASES

Tank Number	Tank Owner	Typical Location	Description	Fabrication Date	Nominal Design Capacity (gallons)	Product Type	Secondary Containment Description	Internal Inspection Last; Next	External Inspection Last; Next	Inflow Control Valve	Liquid Level Mechanism/Overfill Protection	Leak Detection Systems and/or Procedures	Corrosion Protection
O-11	TANK-O	END	Open top	1990	(b) (7)(F), (b) (3) [redacted]	Miscellaneous Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2010; 2015	2010; 2015	(b) (3), (b) (7)(F) [redacted]	[redacted]	[redacted]	None
O-12 (also known as T-12)	TANK-O	Varies	Horizontal, open-top Tiger	Unknown	[redacted]	Crude Oil	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2011; 2016	2011; 2016	[redacted]	[redacted]	[redacted]	Internal Lining
O-15	TANK-O	GPB	Single-walled; open top	Unknown	[redacted]	Miscellaneous Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2010; 2015	2010; 2015	[redacted]	[redacted]	[redacted]	None
O-16	TANK-O	END	Single-walled; open top	Unknown	[redacted]	Miscellaneous Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2010; 2015	2010; 2015	[redacted]	[redacted]	[redacted]	Internal Lining
O-17	TANK-O	Varies	Single wall, open top	Unknown	[redacted]	Miscellaneous Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2010; 2015	2010; 2015	[redacted]	[redacted]	[redacted]	Internal Lining
O-18	TANK-O	Varies	Single wall, open top	Unknown	[redacted]	Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2011; 2016	2011; 2016	[redacted]	[redacted]	[redacted]	Internal Lining
O-21	TANK-O	Varies	Single walled; Open top	1987	[redacted]	Miscellaneous Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2011; 2016	2011; 2016	[redacted]	[redacted]	[redacted]	Internal Lining
O-22	TANK-O	Varies	Flowback Tank	1987	[redacted]	Miscellaneous Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2011; 2016	2011; 2016	[redacted]	[redacted]	[redacted]	Internal Lining
O-23	TANK-O	Varies	Flowback Tank	1987	[redacted]	Miscellaneous Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2011; 2016	2011; 2016	[redacted]	[redacted]	[redacted]	Internal Lining
T-03-9003	BPXA	GPB	Spicer Tank	1983	[redacted]	Various	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2013; 2016	2013; 2016	[redacted]	[redacted]	[redacted]	None

APPENDIX A: ADEC-REGULATED PORTABLE, SHOP-FABRICATED STORAGE TANK DATA TANKS GREATER THAN 10,000 GALLONS ON BPXA LEASES

Tank Number	Tank Owner	Typical Location	Description	Fabrication Date	Nominal Design Capacity (gallons)	Product Type	Secondary Containment Description	Internal Inspection Last; Next	External Inspection Last; Next	Inflow Control Valve	Liquid Level Mechanism/Overfill Protection	Leak Detection Systems and/or Procedures	Corrosion Protection
T-1123	BPXA GWO	MPU	Upright, portable, single wall, skid-mounted	2008	(b) (7)(F), (b) (3) [redacted]	Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2012; 2017	2012; 2017	(b) (3), (b) (7)(F) [redacted]	[redacted]	[redacted]	Internal Lining
T-1124	BPXA GWO	MPU	Upright, portable, single wall, skid-mounted	2008	[redacted]	Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2012; 2017	2012; 2017	[redacted]	[redacted]	[redacted]	Internal Lining
T-14	TANK-O	PS1	Horizontal, rectangular Tiger	Unknown	[redacted]	Miscellaneous hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2010; 2015	2010; 2015	[redacted]	[redacted]	[redacted]	Internal Lining
T-18	TANK-O	Varies	Horizontal rectangular; Tiger	1990	[redacted]	Miscellaneous hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2012; 2015	2012; 2015	[redacted]	[redacted]	[redacted]	Internal Lining
T-19	TANK-O	Varies	Horizontal rectangular; Tiger	1990	[redacted]	Miscellaneous hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2012; 2015	2012; 2015	[redacted]	[redacted]	[redacted]	Internal Lining
T-20	TANK-O	Varies	Horizontal, single wall	1990	[redacted]	Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2012; 2015	2012; 2015	[redacted]	[redacted]	[redacted]	Internal Lining
T-20451 Not in Service	BPXA	END SDI	Vertical, cylindrical, and elevated	2009	[redacted]	Drilling muds and fluids	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	Not in Service	Not in Service	[redacted]	[redacted]	[redacted]	Epoxy coating
T-20452 Not in Service	BPXA	END SDI	Vertical, cylindrical, and elevated	2009	[redacted]	Drilling muds and fluids	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	Not in Service	Not in Service	[redacted]	[redacted]	[redacted]	Epoxy coating
T-21	TANK-O	Varies	Horizontal, single wall	1990	[redacted]	Hydrocarbons	Designed and constructed to BPXA's secondary containment specification (CRT-AK-04-90)	2010; 2015	2010; 2015	[redacted]	[redacted]	[redacted]	Internal Lining
T-22	TANK-O	Varies	Open top, horizontal, double wall	2013	[redacted]	Hydrocarbons	Double wall[1]	New Construction 2013; 2019	New Construction 2013; 2019	[redacted]	[redacted]	[redacted]	Internal Lining

APPENDIX A: ADEC-REGULATED PORTABLE, SHOP-FABRICATED STORAGE TANK DATA
TANKS GREATER THAN 10,000 GALLONS ON BPXA LEASES

Tank Number	Tank Owner	Typical Location	Description	Fabrication Date	Nominal Design Capacity (gallons)	Product Type	Secondary Containment Description	Internal Inspection Last; Next	External Inspection Last; Next	Inflow Control Valve	Liquid Level Mechanism/Overfill Protection	Leak Detection Systems and/or Procedures	Corrosion Protection
T-23	TANK-O	Varies	Open top, horizontal, double wall	2013	(b) (7)(F), (b) (3) [redacted]	Hydrocarbons	Double wall[1]	New Construction 2013; 2019	New Construction 2013; 2019	(b) (3), (b) (7)(F) [redacted]	[redacted]	[redacted]	Internal Lining
T-24	TANK-O	Varies	Open top, horizontal, double wall	2013	[redacted]	Hydrocarbons	Double wall[1]	New Construction 2013; 2019	New Construction 2013; 2019	[redacted]	[redacted]	[redacted]	Internal Lining
T-25	TANK-O	Varies	Open top, horizontal, double wall	2013	[redacted]	Hydrocarbons	Double wall[1]	New Construction 2013; 2019	New Construction 2013; 2019	[redacted]	[redacted]	[redacted]	Internal Lining
T-26	TANK-O	Varies	Open top, horizontal, double wall	2013	[redacted]	Hydrocarbons	Double wall[1]	New Construction 2013; 2019	New Construction 2013; 2019	[redacted]	[redacted]	[redacted]	Internal Lining
T-27	TANK-O	Varies	Open top, horizontal, double wall	2013	[redacted]	Hydrocarbons	Double wall[1]	New Construction 2013; 2019	New Construction 2013; 2019	[redacted]	[redacted]	[redacted]	Internal Lining
T-28	TANK-O	Varies	Open top, horizontal, double wall	2014	[redacted]	Hydrocarbons	Double wall[1]	New Construction 2014; 2019	New Construction 2014; 2019	[redacted]	[redacted]	[redacted]	Internal Lining
T-29	TANK-O	Varies	Open top, horizontal, double wall	2014	[redacted]	Hydrocarbons	Double wall[1]	New Construction 2014; 2019	New Construction 2014; 2019	[redacted]	[redacted]	[redacted]	Internal Lining
T-30	TANK-O	Varies	Open top, horizontal, double wall	2014	[redacted]	Hydrocarbons	Double wall[1]	New Construction 2014; 2019	New Construction 2014; 2019	[redacted]	[redacted]	[redacted]	Internal Lining
T-31	TANK-O	Varies	Open top, horizontal, double wall	2014	[redacted]	Hydrocarbons	Double wall[1]	New Construction 2014; 2019	New Construction 2014; 2019	[redacted]	[redacted]	[redacted]	Internal Lining
T-32	TANK-O	Varies	Open top, horizontal, double wall	2014	[redacted]	Hydrocarbons	Double wall[1]	New Construction 2014; 2019	New Construction 2014; 2019	[redacted]	[redacted]	[redacted]	Internal Lining
T-33	TANK-O	Varies	Open top, horizontal, double wall	2014	[redacted]	Hydrocarbons	Double wall[1]	New Construction 2014; 2019	New Construction 2014; 2019	[redacted]	[redacted]	[redacted]	Internal Lining
T-419-005	Doyon	Doyon Rig 16	Horizontal, rectangular double wall	Unknown	[redacted]	Hydrocarbons	Double wall[1]	2009; 2014	2009; 2014	[redacted]	[redacted]	[redacted]	None
T-8208A	BPXA GWO	MPU	Horizontal, rectangular double wall	1999	[redacted]	Hydrocarbons	Double wall[1]	2012; 2017	2012; 2017	[redacted]	[redacted]	[redacted]	None
T-8208B	BPXA GWO	MPU	Horizontal, rectangular double wall	1999	[redacted]	Hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	[redacted]	[redacted]	[redacted]	None
T-8208C	BPXA GWO	MPU	Horizontal, rectangular double wall	1999	[redacted]	Hydrocarbons	Double wall[1]	2010; 2015	2010; 2015	[redacted]	[redacted]	[redacted]	None

Notes:

1 - The outer wall of a double-walled aboveground oil storage tank is considered secondary containment. Additional lined secondary containment is not required for double-walled tanks if they are equipped with a fixed overfill containment system, a means to monitor the inters itial space (e.g., view port) and a means to drain the intersti ial space, as required by 18 AAC 75.066(e). NOTE: LID MUST BE USED ON OPEN-TOP DOUBLE-WALLED TANKS WHILE IN USE (HOLDING OIL).

APPENDIX B

FACILITY DIAGRAMS

(b) (7)(F), (b) (3)

[redacted]

Gas Pipeline on VSM's

Oil Pipeline on VSM's

Oil & Gas Pipelines (Buried on Seabed)

Oil & Gas Pipeline on VSM's

NS-2 Spill Response Equipment, Access Sites, Staging Areas, or Boom Anchors

Bathymetry in Feet

(See also ACS Map Atlas Sheets 58-60, 62, 65, 71, 72)

BP EXPLORATION (ALASKA) INC.

NORTHSTAR
AREA MAP

DATE:	SCALE:	FIGURE:
March 2012	1" = 2.5 Miles	B-1

pe13568_11.mxd

(b) (7)(F), (b) (3)

[redacted]

(b) (7)(F), (b) (3)

[redacted]

BP EXPLORATION (ALASKA) INC.

NORTHSTAR PIPELINES
LOCATION MAP

DATE:	SCALE:	FIGURE:
March 2012	1" = 6000'	B-2

pe13568_11.mxd

(b) (7)(F), (b) (3)

[redacted]

NS26 ■ WELL

○ WELL SLOT

× 9 SURFACE ELEVATION

← SURFACE FLOW

● FIRE MONITOR STATIONS
Level 2 Process Module and
Along Pipe Rack

PIPELINES

BP EXPLORATION (ALASKA) INC.

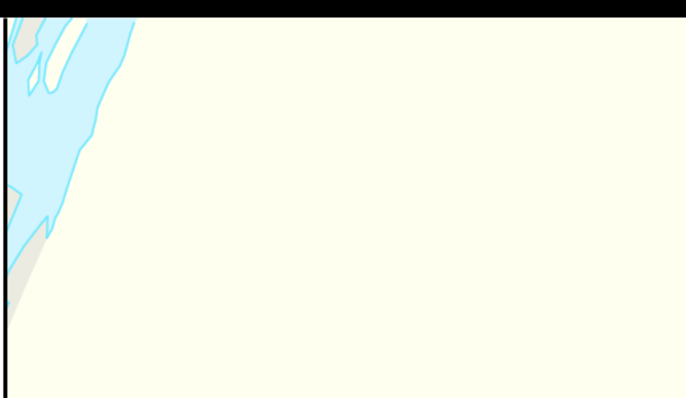
NORTHSTAR SEAL ISLAND LOCATION MAP

DATE:	SCALE:	FIGURE:
March 2012	1" = 100'	B-3

is2011_fms.mxd

(b) (7)(F), (b) (3)

[redacted]



BP EXPLORATION (ALASKA) INC.

NORTHSTAR
PUTULIGAYUK RIVER CROSSING
PLAN VIEW

DATE:	SCALE:	FIGURE:
March 2012	1" = 250'	B-4

nsvp297_11.mxd

APPENDIX C

NORTHSTAR DISCHARGE HISTORY TABLE

APPENDIX C - NORTHSTAR DISCHARGE HISTORY TABLE
JANUARY 2001 THROUGH DECEMBER 2010

Date	Material	Gallons	Water/ Tundra	Event Description	Environmental Impact	Preventative Action	Cleanup Action
9-Mar-01	Lube Oil	110	No	While relocating palletized drums, a fork lift punctured two drums of Escaid 110 (mineral oil). All contents were contained in the secondary containment inside the bermed chemical storage area.	Hydrocarbons to secondary containment. All material was recovered.	Loader operator and spotter have heightened awareness of the hazards of moving drums.	Loader bucket and shovels
4-May-01	Lube Oil	75	No	While relocating palletized drums, a fork lift punctured two drums of Escaid 110 (mineral oil). All contents were contained in the secondary containment inside the bermed chemical storage area.	Hydrocarbons to secondary containment. All material was recovered.	This was an unforeseen mechanical failure.	Clean up was completed utilizing absorbents.
20-Jun-01	Diesel	0.13	Yes	Sheen (approximately 10-15 feet in length and 1-2 feet wide) was discovered on the west side of the island in approximately 2 feet of water. The source of the sheen was a small pile of gravel located about 5-6 feet from the water's edge. Estimated approximately a pint of a petroleum based product was entrained in the gravel.	Oil to water. No impacts were observed.	The cause is still unknown so no preventative action can be recommended. Equipment is visually checked daily and before use.	A containment assessment was conducted and boom was placed around the source and perpendicular to the shore line to help contain the sheen. A backhoe was used to retrieve approximately 1/4 yard of frozen gravel. A small inflatable boat was brought on site, along with pom-pom absorbents (oil snares), to control and collect product in the sheen.
30-Jun-01	Diesel	1	Yes	A sheen was spotted by Northstar helicopter approximately 1/4 mile north of Stump Island and was approximately 50' x 100' wide. The sheen was contained by ice. ACS flew the pipeline, then west along the coast to the Colville River delta and then upriver to Umiat where the sheen had been reported by USFWS on 6/29. No sheen seen on Colville or near Stump Island. ACS ran air boats to near Stump Island and reported no further sheening.	Hydrocarbons to water. No impacts were observed.	None necessary.	ACS ran air boats to near Stump Island and reported no further sheening.
15-Nov-01	Crude Oil	84	No	The fresh air fired unit would not start, during opacity testing, and the heating medium and the NGL temperature dropped. A contract employee noticed fluid leaking on the pad and the leak was traced back to the flange of the NGL Reboiler, which spilled approx 2 barrels of NGL. Approx 25 gal spilled onto the pad and the remaining fluid was captured in secondary containment.	Oil to gravel pad. The material that reached the ground was cleaned up and properly disposed of.	Operations will increase visibility of the process modules any time a significant change in temperature is experienced in the waste heat recovery system. There were several leak points identified and torqued as part of the spill investigation.	Environmental installed temporary spill containment under the leak. The flanges were re-torqued and pressure tested and the NGL Reboiler was returned to service. The material recovered from the secondary containment was returned to the process stream. The material that reached the ground surface was picked up utilizing a bobcat and shovels.
16-Mar-02	Therminol	84	No	Electricians were repairing the 480 volt breaker for slop oil pump P-4830B. A pre-job discussion was held with the unit operator and power was turned off to the pump house. Approximately five minutes after the power was turned off the electrician heard a sound similar to running water. A fluid leak was found coming from overhead piping. The area operator was notified via radio and responded to the call and observed therminol spraying from the AHU. The Area Operator stopped the spray using the unit heater isolation valves. After isolation, the hot Therminol vapors draining from the unit created a significant accumulation of vapors in and around the skid.	Therminol to snow surface. All material was removed.	An investigation is being conducted to determine the cause and preventative action.	Therminol was vacuumed from the containment in the pump house. The remainder of the therminol inside of the module was cleaned with rags/sorbents off the machinery and walls. Shovels were used to scrape up the snow that was affected.
15-Apr-02	Therminol	210	No	A coil failure in the therminol unit resulted in approximately 5 barrels of therminol to flow down through the module to the pad. Contamination circumferenced an area of approximately 1500 square feet.	Therminol to gravel pad. Approximately 1500 square feet. contaminated with therminol.	Preventative action will be recommended during the investigation of the incident.	Material will be reused/recycled if possible. The remaining material will be properly disposed of at Northstar. Clean up was with bobcats, shovels and sorbents.
8-Aug-02	Crude Oil	<0.1	Yes	During a plant upset, radiant heat from the flaring event is suspected to have re-mobilized residual hydrocarbons that remain on the flare boom. The hydrocarbons dripped from the flare boom onto the concrete armoring and water under the flare. (Note: It is also possible that new material, traveling on the inner pipe wall of the flare dripped off the tip.)	Oil to water. No impacts were observed. All materials were recovered from the surface of the water.	The incident that caused the plant shutdown is still being reviewed.	Absorbent boom was immediately placed around the affected area to contain the material and to soak up the materials from the surface of the water. The absorbent materials were placed into oily waste bags for disposal.
14-Dec-02	Crude Oil	0 20	Yes	While calibrating a combustible gas detector, the plant BESD (blowdown emergency shut down) was triggered. During the blow down, unburned hydrocarbon liquid was expelled from the LP flare tip.	Hydrocarbons to tundra. No impacts were noted.	Action team working on preventative measures to eliminate future releases and maintain plant stability.	Cleanup was completed with the usage of shovels and oily waste bags.

APPENDIX C - NORTHSTAR DISCHARGE HISTORY TABLE
JANUARY 2001 THROUGH DECEMBER 2010

Date	Material	Gallons	Water/ Tundra	Event Description	Environmental Impact	Preventative Action	Cleanup Action
23-Dec-02	Crude Oil	<0.1	Yes	The LP compressor shut down due to a loose ground wire on the PLC (programmable logic controller). During the ensuing flare event a small (.0013 gallons) amount of non-combusted hydrocarbons was released to the solid sea ice.	Oil to sea ice. No impacts were observed.	Tighten all wires in the LP control panel.	All contaminated sea ice was scraped clean and disposed of in E&P exempt well, NS-10.
15-Jan-03	Crude Oil	<0.1	Yes	During a walk around following a facility start up, a de minimal amount of hydrocarbon was discovered on the sea ice. Approximately 30'x30' area of sea ice was affected with small "bb"-size drops, amounting to no more than 2 tablespoons total.	Oil to sea ice. No impacts were observed. All material was contained and removed.	Insulation was removed and heat trace was installed.	Cleanup was completed using shovels and oily waste bags. Disposal of contaminated material through E&P exempt well, NS-10.
14-Jun-03	Hydraulic Fluid	20	Yes	Parking brake housing casing for the Zoom boom broke while the Zoom boom was prepping the ice road ramp for the Hovercraft offloading area.	Oil to gravel pad. All materials have been contained on the island gravel surface.	This was an unforeseen mechanical failure.	A Guzzler and heavy equipment were used to remove standing liquids and to remove the slope protection blocks. The contaminated fabric and gravel under the blocks were removed. The slope protection blocks were then washed and replaced in the area.
27-Jun-03	Diesel	<0.1	Yes	During delivery of freight to Northstar Island, the hovercraft was high centered on a ridge of ice and the fuel vent released approximately 1/4 cup of diesel onto the vessel and sea ice. Majority of the material was captured in the pillows and skirt on the vessel.	Oil to sea ice and water. No impacts observed, all material was recovered.	Absorbent is to continue being stored on hovercrafts. A modification to the vents has been completed to contain potentially escaped fluids.	Material was contained at and around source. Absorbent was used to clean up sheen on water surface and was disposed of in the oily waste dumpster at Northstar.
18-Jul-03	Crude Oil	2	Yes	During a flaring event, an LP compressor shutdown occurred that resulted in oil carryover out the LP flare. Approximately 2 gallons of uncombusted hydrocarbon was released from the flare stack.	Oil to water. No impacts were observed.	An investigation is being conducted to determine the cause and preventative action.	Containment boom and sorbent was placed in the impacted area immediately upon discovery and sorbent was put into place to monitor for continued releases. The area was cleaned using manual tools, absorbent and a vac skimmer unit. Blocks were scrubbed to eliminate any residual oil.
20-Jul-03	Crude Oil	<0.1	Yes	The HP compressor had a shutdown resulting in a flare event. The bench and surrounding water were surveyed directly after the flare event and a small sheen was discovered. Approximately 1 tablespoon of residual material was estimated to have been released to the water.	Hydrocarbons to water. No impacts were observed.	The incident that caused the plant shutdown is still being reviewed.	Containment boom was placed around the bench of the island to absorb the sheen. A zodiac was then deployed to determine if further sheening could be found.
17-Dec-03	Crude Oil	<0.1	Yes	A solar generator flamed out, due to new PECC valve installations resulting in in a plant shut down. The flare blower then had a delayed restart due to a ground fault on a power bus. When the flare blower restarted a combustible mixture had ignited in the flare piping.	Hydrocarbons to sea ice. No impacts were observed and all material was recovered.	The solar generator was removed from operation. Solar engineers were contacted and two service representatives flew to the island to perform diagnostic investigation and work.	A shovel used to scrape up waxy crude off of the ice pack.
30-Mar-05	Diesel	322	No	Diesel overflowed a portable storage tank into secondary containment. While heating up the containment to assist in the clean-up, it was discovered that some of the diesel was leaching out with melt water from under the containment and onto the gravel pad.	Hydrocarbons to gravel pad. All material has been removed.	A review of incident with all appropriate staff for lessons learned was conducted. Modification of diesel storage operating procedures was updated.	Contaminated snow was shoveled into temporary storage bins for proper disposal and a loader with a scarifier was used to remove the frozen gravel.
19-Apr-05	Diesel	100	No	During a routine transfer of diesel from the temporary storage tanks a PSV in the system lifted early. The PSV discharge was routed back to a tank that was already full and forced 100 gallons out the overflow line and into the secondary containment. This containment still has diesel volume in it from a previous spill, and began to leak out into the gravel pad beneath it.	Hydrocarbons to gravel pad. All materials were removed from the containment and the gravel pad.	The tanks have been de-inventoried and de-mobed off the island.	Absorbents and an air barrel vacuum were used to recover free standing liquids.
29-Oct-05	Diesel	420	No	While pumping diesel into the outer annulus, returns from the conductor went into cellar.	Hydrocarbons to well cellar. All materials were contained in the well cellars and no impacts were noted.	Until the actual cause can be determined a preventive action can not be addressed.	Liquids were recovered using a vacuum pump truck and returned to the pump trucks holding tank to be use for future well work. Remaining fluids were soaked up using sorbents and placed into oily waste bags. The contaminated gravel and debris were scraped up and placed into oily waste bags.
4-Jan-06	Hydraulic Fluid	0.75	Yes	While removing snow and rubble ice around the west side of the island, a chunk of ice got caught between the blade on the dozer and a hydraulic ram. When the operator attempted to tilt the dozer blade, the ice chunk broke off one of the hydraulic fittings.	Hydraulic oil to sea ice. All materials were recovered and no impacts were noted.	The project has been shut down until preventative actions can be determined and implemented.	Shovels and small hand tools were used to scrape up the contaminated snow and ice. The materials were then placed into an oily waste bags to be stored prior to disposal.

APPENDIX C - NORTHSTAR DISCHARGE HISTORY TABLE
JANUARY 2001 THROUGH DECEMBER 2010

Date	Material	Gallons	Water/ Tundra	Event Description	Environmental Impact	Preventative Action	Cleanup Action
26-Feb-06	Diesel	180	No	Fuel was leaking from a vent line from the containment on the diesel day tank.	Diesel to secondary containment. All materials were contained and recovered.	More thorough equipment inspections by operators and mechanics to identify damaged parts.	The return fuel line was removed and plugged. Liquids were drained out of the containment and placed into drums for storage until materials could be recycled. Sorbents were then used to wipe up the materials that leaked onto the floor and placed into oily waste bags.
15-May-06	Diesel	<0.1	Yes	A Ditch Witch, was idling when a small drip onto the ice was noticed. Upon inspection, it was noted that a gasket sealing the fuel level sensor had failed. The amount of the spill was less that 1 cup.	Hydrocarbons to sea ice.. All materials were contained on the surface of the sea ice and recovered.	The machine was taken out of service and removed from the island for repairs.	Absorbents were used to soak up the liquids from the surface of the ice and shovels were used to scrape up the contaminated ice.
20-May-06	Hydraulic Fluid	<0.1	Yes	Sheen was discovered off of the east side of the island where excavation for shoreline protection repairs was being done. The source of the sheen is believed to be from a Trac Hoe that had a fitting leak on the 15th of May.	Hydrocarbons to water. All materials released have been contained and have been recovered.	More thorough equipment inspections by operators and mechanics before and during operations.	Absorbent boom and pads were used to capture the sheen.
5-Feb-07	Motor Oil	0 84	Yes	During construction of the ice storage pad, an alternator mounting bracket on a pumper truck broke due to vibration stress and general use. When it broke, the alternator dropped and hit an oil cooling line, releasing two to three quarts of oil onto the ice.	Hydrocarbon to sea ice. All material was removed and no impacts were noted.	The damaged machine was removed from Northstar within the hour. Thorough inspections by operators and mechanics during operations will be performed.	Immediately upon discovery, a temporary secondary containment was placed under the leak. Absorbent pads were then used to absorb the motor oil from ice surface. Hand tools were used to chip out the remaining contaminated ice and placed in a snowmelt bin for disposal.
5-Feb-07	Diesel	0 84	Yes	A connecting hose between two diesel tanks on a portable heater became loose and 1 gallon of diesel was spilled to the ice road.	Diesel to sea ice. No impacts were noted.	The diesel was removed from the heater and the equipment was returned for repairs.	Heavy equipment was used to chip up the contaminated ice and was then placed into a bin to be sent to the G&I for UIC Class I injection.
22-Mar-07	Hydraulic Fluid	<0.1	Yes	While offloading the amphibious backhoe from the lowboy trailer a leak developed from a broken bolt on a hydraulic pump housing.	Hydrocarbons to snow and sea ice. All materials were contained and recovered. No impacts were noted.	This was an unforeseen mechanical failure.	A shovel was used to scrap up the contaminated snow off of the sea ice surface. Absorbents were additionally used to wipe off the backhoe.
11-Apr-07	Lube Oil	0 84	Yes	A bolt supporting the bracket that holds the oil cooler on the loader broke while in operation. Lube oil leaked out from the seal area between the cooler and the oil filters.	Hydrocarbons to sea ice. All materials were contained and removed.	This was an unforeseen failure of a bolt.	A loader with a bucket was used to scrape up the affected ice. Shovels were then used to place the contaminated materials into bins until the materials could be processed.
20-Apr-07	Hydraulic Fluid	2.10	Yes	A hydraulic fluid spill from an unknown source was noticed by personnel during a routing walk around. All equipment working in the area was inspected and no signs indicated a visible leak.	Hydraulic fluid to sea ice and snow. All materials were contained on the surface of the sea ice.	The cause is still unknown so no preventative action can be recommended. Equipment is visually checked daily and before each use.	A loader and a bobcat were used to scrape up the contaminated snow and ice and placed into a pile. The materials were transferred to a storage bin and taken to the Northstar G&I for processing and disposal.
4-May-07	Hydraulic Fluid	1 68	Yes	During a repair construction project of a concrete block and berm replacement two quarts of hydraulic oil spilled from a bad "O" ring on an amphibious pontoon backhoe. An additional one quart was spilled the following day from an additional bad "O" ring.	Hydrocarbons to sea ice. All materials were contained and removed.	A review of the amphibious pontoon backhoe on whether to remain in service for this construction project was conducted.	Approximately 1 cubic yard of hydraulic oil contaminated snow was removed from the sea ice and placed in a bin for disposal.
18-May-07	Hydraulic Fluid	0.42	Yes	While excavating a trench around the island, the ditch witch developed a leak from a hydraulic fluid valve. Hydraulic fluid spilled onto the sea ice and into the trench that was being excavated.	Hydrocarbons to snow and ice. All of the materials were recovered from both the surface of the ice and water.	This was an unforeseen mechanical failure.	Shovels were used to scrape up the contaminated snow and ice from the spill site. Absorbents were additionally used to soak up the materials that was on the surface of the water.
20-May-07	Diesel	<0.1	Yes	The leak was detected on the gravel pad from a leak on the water fuel separator around the sending unit of a snow cat. Further investigation discovered that the fuel had also leaked onto the sea ice where the unit had been parked.	Hydrocarbons to gravel pad and sea ice. All materials were recovered.	More thorough equipment inspections prior to departing to remote locations.	Shovels were used to scrape up the contaminated snow, ice, and gravel.
20-May-07	Hydraulic Fluid	0.10	Yes	A seal fitting developed a leak on the main mast of a backhoe while being used to remove graveled snow from the production facility.	Hydrocarbons to snow and gravel. The materials were contained to the site and recovered.	More thorough equipment inspections by operators and mechanics to identify bent or damaged parts.	Absorbents were used to soak up the sheen from runoff and shovels were used to scrape up contaminated snow and gravel.

APPENDIX C - NORTHSTAR DISCHARGE HISTORY TABLE
JANUARY 2001 THROUGH DECEMBER 2010

Date	Material	Gallons	Water/ Tundra	Event Description	Environmental Impact	Preventative Action	Cleanup Action
12-Aug-07	Diesel	435.12	No	A diesel release into well cellar, NS-29, was due to thermal expansion from high ambient air temperature.	Hydrocarbons to containment. All materials were contained in the well cellar.	Additional warning text was placed on the HMI graphic to strap the OA in the event of injection gases reaching 225°F. The high alarm on the HMI was also reset at 225°F.	Liquids were recovered using an air actuated drum vacuum. Remaining fluids were soaked up using absorbents and placed into oily waste bags.
31-Dec-07	Hydraulic Fluid	2 94	Yes	During construction of the Northstar ice road, a pumper unit used to flood the ice road had a 1/2" power steering hose fail.	Hydrocarbons to sea ice. All materials were contained and were recovered.	This was an unforeseen mechanical failure.	Shovels were used to scrape up the contaminated snow and ice and placed into oily waste bags for transportation.
9-Aug-08	Hydraulic Fluid	0.42	Yes	A backhoe was on a barge performing dredging operations when a hydraulic leak resulted in a small sheen on the seawater.	Hydraulic oil to seawater. All spilled material was recovered.	All fittings and seals on the backhoe were wrapped with absorbent materials. A liner was placed under the unit before continuing the job again.	Absorbent materials were used to clean up the affected areas of the backhoe and barge surfaces and inside the containment boom to recover sheen in the water.
11-Jan-09	Lube Oil	120.00	No	An oil leak was discovered on a high pressure turbine oil supply line.	Hydrocarbons to secondary containment. No impacts were noted.	The oil supply line was replaced with a braided stainless steel flexible line to reduce stress due to vibration. The other Northstar compressor was checked and repaired as necessary.	A barrel vac system was used to recover standing liquids. Absorbents and rags were used to clean up other affected areas.
17-Feb-09	Hydraulic Fluid	8.40	Yes	During ice road maintenance, the threaded nipple holding the hydraulic filter on a snow blow failed, causing the filter to detach.	Hydrocarbons to ice. All material was recovered.	The unit was loaded onto a truck and trailer and hauled to Deadhorse for repairs.	Absorbent material was used to remove standing liquid and shovels were used to remove the spilled hydraulic fluid from the snow and ice.
23-May-09	Motor Oil	<0.1	Yes	A bobcat developed a motor oil leak from the oil line that goes from the engine to the cab heater. Approximately 1 cup of motor oil was released to the ground before the leak was detected by ground personnel.	Oil to water: Temporary sheen on water body surface. No impacts were noted.	Boom layers will be placed directly along the shoreline of the island to prevent any future pad releases from entering the seawater during work activities. Boom will also be placed along the shoreline in work areas as the crew moves along as a preventative action.	Absorbent boom was placed around the sheen to capture the material on the seawater and a hot water wash was used on the gravel and ice to clean out the spaces between the block work in the bench construction. All impacted material was removed from the site by shoveling the material into oily waste bags and removed for proper disposal.
26-May-09	Diesel	<0.1	Yes	During fueling operations of a jetting pump, a fuel can with a separate funnel was utilized. As the fueler poured the fuel into the funnel, the funnel moved and fuel belched out of the top of the tank. The pump was located in secondary containment however, the containment was ineffective because the fuel tank on the pump was at the edge of the secondary containment. Approximately 1/2 cup of fuel spilled with fuel going into the secondary containment and water.	Hydrocarbons to water and secondary containment. All materials were recovered.	A review of the incident found action items to situate equipment farther from the edge of water, utilized two people when fueling equipment, better placement of equipment within the containment, and utilize fuel cans with built-in spouts.	Absorbent booms and a viscous sweep were used to contain and recovered spilled material to the secondary containment and the water.
5-Feb-10	Hydraulic Fluid	0.42	No	During snow removal operations the operator noticed a small hydraulic oil drip line in the snow. The operator stopped the unit and placed a liner under the tire and called for assistance.	Hydraulic oil to snow. No impacts were noted. All material was recovered.	The hydraulic oil line fittings were repaired and additional equipment was inspected.	The contaminated snow was removed and placed into a bin for future disposal. The absorbents were placed into an oily waste bag and placed in the onsite oily waste dumpster.
24-Feb-10	Hydraulic Fluid	20.16	Yes	The hydraulic hose on snow blower rubbed on the side of the tank resulting in a leak.	Hydraulic oil to snow and ice. No impacts were noted. All material was recovered.	All snow blower units are having suspected hoses examined. Hoses are being rerouted, when possible, or having protection guards installed to prevent future potential spills.	Heavy machinery scraped up 45 cubic yards of contaminated snow and ice for disposal.
27-Apr-10	Hydraulic Fluid	<0.1	Yes	The Hovercraft lost prop pitch control due to a lost bolt in the assembly. Hydraulic oil was leaking from the hole onto the deck and into the bilge. Additional fluid on the prop blew onto the sea ice behind the hovercraft.	Hydraulic oil to sea ice. No impacts were noted.	The craft system was examined by the crew and all control valve bolts were all wire tied and re-torqued.	Standing liquids were cleaned using absorbent pads and the contaminated snow was shoveled into bins for disposal at the G&I facility.